2005

ANNUAL
REPORT

Shell Canada Limited

Shell Canada Limited

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Unless the content indicates otherwise, the terms Shell, Shell Canada, Shell Canada Limited, Corporation, Company, we, our and its are used interchangeably in this report to refer to Shell Canada Limited and its consolidated subsidiaries.

The terms Royal Dutch Shell and Royal Dutch Shell plc are used interchangeably in this report to refer to Royal Dutch Shell plc, which is Shell Canada's majority shareholder. The term Shell Group refers to the worldwide Royal Dutch Shell enterprise as a whole, including Royal Dutch Shell plc.

This annual report contains references to measures commonly referred to as non-GAAP measures. Additional disclosure relating to these measures can be found on pages 1,18 and 88.

This report contains "forward-looking statements" based upon management's assessment of the Corporation's future plans and operations. Forward-looking statements can be identified by words such as "anticipate," "believe," "expect," "plan," "intend," "forecast," "target," "project" or similar words suggesting future outcomes or statements regarding an outlook.

The forward-looking statements contained in this report include references to anticipated growth and long-term profitability, future capital and other expenditures, organizational capability, the Corporation's plans for growth, development, drilling, construction and expansion, resources and reserves estimates, future production of resources and reserves, receipt of regulatory approvals, reduction in unit costs, operational and product reliability, project execution, refining margins, market share and market conditions. Forward-looking statements of this nature are also contained in the Corporation's filings with Canadian and U.S. securities regulatory authorities.

Readers are cautioned not to place undue reliance on forward-looking statements. Although the Corporation believes that the expectations represented by such forward-looking statements are reasonable based on the information available to it on the date of this report, there can be no assurance that such expectations will prove to be correct.

Forward-looking statements involve numerous assumptions, known and unknown risks, and uncertainties that may cause the Corporation's actual performance or results to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These assumptions, risks and uncertainties include, but are not limited to, demand for oil, gas and related products, disruptions in supply, fluctuations in oil and gas prices, industry operating conditions, operating costs, stakeholder engagement, project startup, schedules and execution, market competition, operational reliability, product quality, labour availability, shortages of materials and equipment, the uncertainties involving the geology of oil and gas deposits and reserves estimates, including the assumption that the quantities estimated can be found and profitably produced in the future, fluctuations in foreign currency exchange rates, general economic conditions, commercial negotiations, changes in law or government policy, and other factors, many of which are beyond the control of the Corporation. Readers should refer to the Management's Discussion and Analysis and Risk Management sections of this report for further discussion of the risks and uncertainties identified by the Corporation.

The forward-looking statements contained in this report are made as of March 10, 2006, and the Corporation does not undertake any obligation to update publicly or to revise any of the forward-looking statements contained in this report, whether as a result of new information, future events or otherwise. This cautionary statement expressly qualifies the forward-looking statements contained in this report.

HIGHLIGHTS

FINANCIAL HIGHLIGHTS	2005
Earnings ($ millions)	2 014
Cash flow from operations ($ millions)[1]	3 056
Capital, exploration and predevelopment expenditures ($ millions)	1 715
Return on average common shareholders' equity (%)	27.3
Return on average capital employed (%)[2]	26.8
Per common share (dollars)	
Earnings – basic	2.44
Earnings – diluted	2.41
Dividends	0.367

OPERATING HIGHLIGHTS	2005
PRODUCTION	
Natural gas – gross (mmcf/d)	512
Ethane, propane and butane – gross (bbls/d)	23 300
Condensate – gross (bbls/d)	15 300
Bitumen – gross (bbls/d)	
Exploration & Production	8 900
Oil Sands	95 900
Total bitumen	104 800
Sulphur – gross (long tons/d)	5 300
Crude oil processed by Shell refineries (m^3/d)	44 900
SALES	
Synthetic crude sales excluding blend stocks (bbls/d)	99 400
Purchased upgrader blend stocks (bbls/d)	37 100
Total synthetic crude sales (bbls/d)	136 500
Petroleum product sales (m^3/d)	49 100
PRICES	
Natural gas average plant gate netback price ($/mcf)	8.23
Ethane, propane and butane average field gate price ($/bbl)	34.79
Condensate average field gate price ($/bbl)	66.76
Synthetic crude average plant gate price ($/bbl)	57.55

[1] Cash flow from operations is a non-GAAP measure and is defined as cash flow from o
working capital and operating activities (see page 18).

[2] Return on average capital employed is a non-GAAP measure and is defined as earnings
divided by the average of opening and closing common shareholders' equity plus preferre
borrowings.

COMMITMENTS

COMPANY GOALS

> **Growth and profitability** are the Company's main goals within an overarching commitment to sustainable development. Pursuit of a strong and diverse portfolio of growth opportunities requires sizable capital investment funded by robust and profitable base businesses. Although the return on average capital employed may fall in periods of heavy investment, the resulting growth will support future, long-term profitability in a continuing cycle.

SUSTAINABLE DEVELOPMENT

> **Sustainable development** is the integration of economic, environmental and social considerations into the Company's day-to-day activities and future plans. Shell Canada aims to provide value to its customers in ways that respect environmental and social concerns while contributing to the economic benefit of its shareholders, employees and society at large.

OPERATIONAL EXCELLENCE

> **A focus on operational excellence** means that all employees are accountable for what they can control in the areas of costs and operations. This includes the operational performance of every part of the Company in terms of plant reliability, project execution, health, safety and the environment, customer satisfaction and stakeholder engagement.

SAFETY

> **The health and safety** of employees and contractors is Shell Canada's top priority. The Company's safety goal is to cause "no harm to people."

COMPLIANCE

> **Good corporate governance** is fundamental to the integrity and reputation of the Company. Policies and procedures are in place to foster compliance with applicable regulations governing every aspect of the Company's business. All Shell employees must conduct business in accordance with these policies and procedures, and Shell's business principles and code of ethics.

HIGHLIGHTS

FINANCIAL HIGHLIGHTS	2005	2004	2003
Earnings ($ millions)	**2 014**	1 286	810
Cash flow from operations ($ millions)[1]	**3 056**	2 129	1 701
Capital, exploration and predevelopment expenditures ($ millions)	**1 715**	951	713
Return on average common shareholders' equity (%)	**27.3**	21.3	15.4
Return on average capital employed (%)[2]	**26.8**	19.9	13.1
Per common share (dollars)			
Earnings – basic	**2.44**	1.56	0.98
Earnings – diluted	**2.41**	1.55	0.97
Dividends	**0.367**	0.313	0.273

OPERATING HIGHLIGHTS	2005	2004	2003
PRODUCTION			
Natural gas – gross (mmcf/d)	**512**	540	562
Ethane, propane and butane – gross (bbls/d)	**23 300**	25 100	26 700
Condensate – gross (bbls/d)	**15 300**	15 200	16 800
Bitumen – gross (bbls/d)			
Exploration & Production	**8 900**	8 100	9 200
Oil Sands	**95 900**	81 300	46 300
Total bitumen	**104 800**	89 400	55 500
Sulphur – gross (long tons/d)	**5 300**	5 600	5 900
Crude oil processed by Shell refineries (m^3/d)	**44 900**	45 100	42 900
SALES			
Synthetic crude sales excluding blend stocks (bbls/d)	**99 400**	83 700	46 100
Purchased upgrader blend stocks (bbls/d)	**37 100**	38 200	17 700
Total synthetic crude sales (bbls/d)	**136 500**	121 900	63 800
Petroleum product sales (m^3/d)	**49 100**	47 500	45 700
PRICES			
Natural gas average plant gate netback price ($/mcf)	**8.23**	6.49	6.46
Ethane, propane and butane average field gate price ($/bbl)	**34.79**	28.71	25.48
Condensate average field gate price ($/bbl)	**66.76**	50.46	41.13
Synthetic crude average plant gate price ($/bbl)	**57.55**	44.67	34.18

[1] Cash flow from operations is a non-GAAP measure and is defined as cash flow from operating activities before movement in working capital and operating activities (see page 18).

[2] Return on average capital employed is a non-GAAP measure and is defined as earnings plus after-tax interest expense on debt divided by the average of opening and closing common shareholders' equity plus preferred shares, long-term debt and short-term borrowings.

RESULTS IN 2005

- Record earnings and cash flow in 2005 were due mainly to record hydrocarbon volumes and solid operating performances by all of Shell's business units, which allowed the Company to capitalize on strong commodity prices and refining margins. Shell Canada's return on average capital employed was 26.8 per cent.
- Constrained global supply combined with growth in demand pushed crude oil prices to record high levels in 2005. The average annual price of crude oil in 2005 was $56.56 US per barrel (West Texas Intermediate) compared with $41.40 US in 2004. Natural gas prices averaged $8.71 Cdn per thousand cubic feet in 2005 compared with $6.52 Cdn in 2004. Market differentials between light and heavy crude oil remained wide.
- Oil Products earnings benefited from strong refining margins, which resulted from low North American inventories and strong demand. Marketing margins remained depressed in a highly competitive environment.
- Capital, exploration and predevelopment expenditures for 2005 were $1,715 million compared with $951 million in 2004, which represents an 80 per cent increase year over year.

AT A GLANCE

Shell Canada Limited is a large integrated petroleum company in Canada comprising three business units supported by a number of corporate departments.

PROFILE

EXPLORATION & PRODUCTION

Exploration & Production explores for, produces and markets natural gas, natural gas liquids, bitumen and sulphur. This upstream business operates four natural gas processing facilities in the Foothills of Alberta and, until December 31, 2005, an in situ bitumen facility near Peace River, Alberta. Effective January 1, 2006, the Peace River business was transferred to Shell Canada's Oil Sands business. The Company also has a 31.3 per cent share of the Sable Offshore Energy Project, which produces natural gas and natural gas liquids off the coast of Nova Scotia.

OIL SANDS

Oil Sands: Shell Canada holds a 60 per cent interest in the Athabasca Oil Sands Project (AOSP). The AOSP's fully integrated operations include the Muskeg River Mine and extraction plant located north of Fort McMurray in northern Alberta and the Scotford Upgrader adjacent to Shell's Scotford Refinery near Edmonton, Alberta. Shell holds leases in the Athabasca area containing recoverable bitumen estimated at more than 6.5 billion barrels, excluding additional leases acquired in 2005. Effective January 1, 2006, Oil Sands is responsible for Shell's Peace River in situ bitumen business.

OIL PRODUCTS

The Oil Products business manufactures, distributes and markets refined petroleum products across the country. Oil Products also procures crude oil and feedstocks for Shell's refineries in Montreal, Quebec; Sarnia, Ontario; and Fort Saskatchewan, Alberta. The refineries convert crude oil into gasoline, diesel, aviation fuels, solvents, lubricants, asphalt and heavy fuel oils. The Company's Canada-wide network of 1,681 Shell-branded retail sites includes convenience food stores and car wash facilities.

ACHIEVEMENTS

- **RECORD EARNINGS** of $665 million
- **RETURN ON AVERAGE CAPITAL EMPLOYED** of 37.2 per cent
- **ACHIEVED A HIGHER RATE OF NATURAL GAS PRODUCTION** going into 2006 than at the beginning of 2005
- **MAJOR LAND ACQUISITIONS** in Alberta and British Columbia and exploration licences offshore Newfoundland and Labrador
- **E&P GROSS NATURAL GAS RESERVES ADDITIONS** essentially replaced annual production

LOOKING FORWARD

- **CONTINUE TO GROW PRODUCTION** in the Foothills of Alberta by developing existing and new assets
- **SUSTAIN PRODUCTION** in the current Sable Offshore Energy Project fields
- **DRILL FIRST EXPLORATION WELL** in the Orphan Basin offshore Newfoundland and Labrador
- **SIGNIFICANTLY GROW** the Unconventional Gas business
- **COMPLETE REGULATORY HEARINGS** on the Mackenzie Gas Project

- **RECORD EARNINGS** of $790 million
- **RETURN ON AVERAGE CAPITAL EMPLOYED** of 29.4 per cent
- **AVERAGE BITUMEN PRODUCTION** at 103 per cent of the 155,000 barrels per day design rate
- **IMPROVED RELIABILITY** at the Scotford Upgrader
- **ACQUISITION OF ADDITIONAL ATHABASCA OIL SANDS** leases for potential future expansions

- **MAINTAIN PRODUCTION** and improve profitability from existing operations
- **OBTAIN REGULATORY APPROVALS** for production optimization and expansion plans
- **COMPLETE FIRST MAJOR TURNAROUND** of the AOSP for both the mine and the upgrader in mid-2006
- **START CONSTRUCTION** of the first mine and upgrader expansion in 2006
- **CONTINUE TO ADVANCE** front-end engineering for long-term growth plans, including Peace River expansion

- **EARNINGS** of $438 million
- **RETURN ON AVERAGE CAPITAL EMPLOYED** of 19.9 per cent
- **RECORD LIGHT OIL** production
- **COMPLETED CONSTRUCTION** of ultra-low-sulphur diesel projects on time and within budget
- **SUCCESSFUL LAUNCH** of Shell V-Power™ premium gasoline

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- **COMPLETE COMMISSIONING** of ultra-low-sulphur diesel supply infrastructure in early 2006, ahead of the legislated deadline
- **CONTINUE TO IMPROVE** manufacturing reliability and efficiency
- **WORK TO IMPROVE** retail market share
- **CONTINUE TO CREATE VALUE** through strategic alliances throughout the Oil Products business
- **OFFER QUALITY, DIFFERENTIATED FUELS** and lubricants reliably and with a strong brand image

EXPLORATION & PRODUCTION

E&P's strategy in 2006 is to increase Shell's natural gas production and reserves.

John Vassaur (facing), Drilling Engineer at the Peace River in situ bitumen complex, explains the mechanics of a "walking" drilling rig to Senior Thermal Engineer Mirko Zatka (left) and new-hire Production Engineer Mathieu Rae.

EXPLORATION & PRODUCTION

E&P's strategy in 2006 is to increase Shell's natural gas production and reserves.

[illegible] industry goals include reducing [illegible] costs and improving efficiency


Warning

PRESIDENT'S MESSAGE

Feet on the ground,
eyes on the horizon.

CLIVE MATHER
President and Chief Executive Officer

It gives me great pleasure to report on Shell Canada's progress in 2005, including the headline achievement of $2 billion in full-year earnings. It was only four years ago that earnings broke the $1 billion barrier and few of us could have imagined doubling that result in such a short time.

Shell Canada's 2005 results reflect not only the prevailing business environment throughout the year, but also strong operating performances by our business units. The Company's initial investments in oil sands are already yielding substantial benefits and we are planning major expansions in the coming years. Natural gas production from Shell's Foothills fields and from the unconventional gas business is increasing, all of which helps provide a firm foundation on which to build a sustainable future.

Keys to the Company's success and sustainable growth are its people and its ability to exploit technology. Shell Canada has an enviable workforce – respected for its values, expertise and commitment. Last year, we attracted a record number of new hires as we prepare for a series of major growth projects in the future. We also demonstrated our capacity to develop and deploy leading-edge technology in many areas of business. This has resulted in exploration success and improvements to environmental performance, costs and customer satisfaction. Further advances will be needed to keep ahead of the competition and deliver energy solutions to help address environmental issues such as climate change and sustainability.

For the second consecutive year Shell Canada posted record earnings

Financial Performance

For the second consecutive year, Shell Canada posted record earnings, which totalled $2,014 million in 2005, or $2.44 per common share, compared with $1,286 million or $1.56, respectively, in 2004. In addition to strong operational performances, continuing high commodity prices, strong refining margins and an increasing contribution from our Oil Sands business were the main reasons for the 56.6 per cent increase over the previous year. Cash flow reached a record high of $3,056 million compared with $2,129 million in 2004.

Between June 1997, when Shell last undertook a share split, and March 2005, Shell Canada's share price rose to more than $90 per common share from around $20. At the end of April, our shareholders approved a three-for-one share split, which took effect June 21, 2005. Total shareholder return for 2005 was 59.3 per cent and quarterly dividends increased to $0.11 per common share from $0.083.

Operational Performance

Total hydrocarbon production in 2005 reached a record high, with the Athabasca Oil Sands Project (AOSP) achieving an average production rate of 159,900 barrels per day (bbls/d) of bitumen.

At year-end 2005, natural gas production was higher than at the end of 2004, which gives us confidence that we can now overcome natural field decline. This achievement was due in part to Shell's Tay River well in the Foothills of Alberta. Tay River came on stream in early May and, following subsequent retubing, soon became the most prolific land-based natural gas producing well in Canada in recent years. During 2005, two additional wells in the South Venture field of the Sable Offshore Energy Project (SOEP) also came on stream, helping to maintain production levels offshore Nova Scotia.

MEMBERS OF SHELL CANADA'S SENIOR MANAGEMENT TEAM, FROM LEFT:
Ian Kilgour, Senior Vice President, Exploration & Production; Cathy Williams, Chief Financial Officer; Tim Bancroft, Vice President, Sustainable Development, Technology and Public Affairs; Clive Mather, President and Chief Executive Officer; David Weston, Senior Vice President, Oil Products; Paul Lapensée, Director, Corporate Strategies; Brian Straub, Senior Vice President, Oil Sands; David Fulton, Vice President, Human Resources.

In 2005, Exploration & Production (E&P) more than tripled its basin-centred gas (BCG) landholdings with important acquisitions in northeast British Columbia and the area of Hinton, Alberta. Following promising test results from BCG wells along the Alberta/British Columbia border, Shell Canada delivered its first BCG to market in November.

In November, Shell and the other proponents of the Mackenzie Gas Project were pleased to announce our readiness to proceed to public hearings after a six-month hiatus. Following intensive discussions, which addressed many of the important issues, we felt able to resume work on this important project.

Our Oil Sands business made remarkable progress in 2005, with the AOSP achieving sustained, reliable bitumen production in excess of the 155,000 bbls/d design rate. To support longer-term growth, Shell Canada filed regulatory applications in April for its Oil Sands mining and upgrading expansion projects and, in the second half of the year, acquired several additional oil sands leases in the Athabasca area. Although the average synthetic crude oil price strengthened over the year, heavy oil market differentials remained relatively wide and unit cash operating costs reflected rising costs for energy, materials and services.

In 2005, our Oil Products business faced a number of challenges in the form of supply disruptions and price volatility. Gasoline prices spiked at more than $1.00 per litre at the pump in early September, as our refineries and distribution systems worked hard to maintain the supplies of refined products to our customers in the face of extremely tight crude oil supply. The gap between supply and demand was largely the result of reduced crude and refined product availability due mainly to closures and hurricane damage to facilities in the U.S. Gulf of Mexico. Operational issues at our refineries, particularly the Montreal East Refinery, did not help the situation.

Marketing margins remained tight throughout the year, but we were able to maintain market share in an extremely competitive environment. Oil Products executed the successful launch of Shell V-Power™ premium gasoline, which is already having an impact in the market, and, in alliance with Flying J Canada Inc., opened the first co-branded travel plaza in Alberta.

Although Shell Canada's safety performance was good by industry standards, the number of lost-time incidents (LTIs) recorded in 2005 was disappointing. Consequently, we are placing even more focus on developing a safety culture that encourages people to look out for themselves and look out for others. Our goal is to embed a safety culture in the hearts and minds of every Shell employee and contractor right across the Company.

I know that we can improve, because there are already many excellent examples of best practice in the company. In February 2005, Montreal East Refinery celebrated five million hours without an LTI and, in July, Muskeg River Mine achieved one year and four million hours without an LTI. In September, Shell's Foothills Operations recorded one million hours LTI-free and finally, in December, employees and contractors at our Waterton sour gas complex passed the remarkable milestone of two million hours and five years without an LTI.

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In Shell Canada, sustainable development belongs firmly in the mainstream of business.

The integration of economic, environmental and social considerations remains the umbrella under which the Company conducts all its business activities. In Shell Canada, sustainable development belongs firmly in the mainstream of business and delivers real benefits to the Company in many ways, not least economic.

While cost savings and other economic benefits are important, sustainable development is much broader than this. Society requires that companies conduct business in an environmentally and socially responsible manner. Our licence to operate increasingly depends on stakeholder support across society, ensuring that all Canadians benefit from our activities. Our licence to grow depends on using new ideas and new technology to reduce emissions and energy consumption, leaving a much smaller environmental footprint. The combination of energetic, innovative people and technological advances is the key to unlocking the door to the sustainable development of our present and future resources.

Shell Canada is investing in research and recruitment that will lead to new technology and new business solutions, and we value our association with various Canadian universities. We also value our relationship with Royal Dutch Shell plc, our majority shareholder, which provides access to Shell Group's international research centres.

Shell Canada is also attracting a steady supply of well-educated technical and professional staff, but we will need many more to pursue our aggressive growth plans. The Company offers an employee value proposition that includes competitive pay and conditions, and opportunities for continuous learning and challenging work. I believe we are on the right track. For example, Mediacorp Canada Inc. placed Shell among Canada's Top 100 Employers for the sixth year in a row. Also in 2005, *Today's Parent* magazine named Shell Canada one of Canada's Top 10 "family friendly" employers.

Shell employees and retirees responded to the leadership and hard work of our 2005 United Way campaign team and the total Shell contribution to the United Way campaigns across Canada was a record $5.2 million. This kind of generosity is part of what makes our Company special.

> I am proud of Shell Canada's corporate governance standards and have confidence in the integrity of our financial reporting systems.

Corporate Governance and Compliance

The Company places the utmost importance on complying with all legal and regulatory requirements, responding promptly to required changes in reporting. We work hard to communicate sound financial and operational information to our shareholders. I am proud of Shell Canada's corporate governance standards and have confidence in the integrity of our financial reporting systems.

Shell also continues to look for ways to improve and communicate, listening to suggestions from stakeholders and learning from others. For example, in 2005, the board of directors appointed an independent Lead Director to complement the role of the Chairman of the Meetings of the Board. In addition, the board approved two new committees to focus on pension administration and health, safety, environment and social responsibility, which are issues with increasingly detailed requirements. The board also approved an independence policy, which formalizes the existing practice of selecting only independent directors to serve on the board committees.

In 2006, we filed our fourth annual certification that Shell Canada is in compliance with Section 302 of the *Sarbanes-Oxley Act* and similar Canadian requirements.

[illegible]

In mid-November, our board approved the largest capital investment program in Shell Canada's history. The $2.7 billion program for 2006 (an increase of almost 60 per cent over 2005 actual capital spending) launched the Company on a growth path in all areas of the business. The potential exists to increase our total hydrocarbon production by more than 50 per cent by the end of the decade.

The 2006 investment plan will help us take advantage of the anticipated strong business outlook and continuing high commodity prices. E&P plans to invest half of its $1.0 billion total to maintain the level of natural gas production in our existing areas of operation in the Foothills and offshore Nova Scotia. The other half will support growth opportunities that include unconventional gas in Western Canada and the Mackenzie Gas Project in the Far North.

I personally thank all of our employees, past and present.

The Oil Sands total investment program in 2006 is about $1.1 billion. A little over half of this will be directed to growth projects, including the first AOSP expansion. The remainder is earmarked for projects to improve profitability, optimize production and sustain operations. At the start of 2006, Oil Sands assumed responsibility for the Peace River in situ bitumen business, which used to be part of E&P. This is a logical step to ensure we optimize synergies across our heavy oil operations.

Oil Products will direct about 70 per cent of its $510 million planned expenditures to meet legislative requirements, primarily the commissioning of our ultra-low-sulphur diesel projects at Scotford and Montreal East refineries, and to maintain the integrity of our manufacturing and distribution supply infrastructures and marketing networks. Other investment capital will be directed to improving the profitability and competitive position of our downstream businesses.

Finally, I personally thank all of our employees, past and present, who have worked so hard to provide the Company with the solid financial and operational foundation from which to grow. I am privileged to be their colleague. Their skill and dedication turn our investments into successful, sustainable operations. Their enthusiasm and innovation make this company such a great place to work.

Clive Mather
President and Chief Executive Officer

March 10, 2006

Growth

Profitability

Sustainable Development

MANAGEMENT'S DISCUSSION AND ANALYSIS

IN THIS MANAGEMENT'S DISCUSSION AND ANALYSIS

All information is reported in Canadian dollars and in accordance with Canadian generally accepted accounting principles (GAAP) unless otherwise stated.

Certain financial measures are not prescribed by Canadian GAAP. These non-GAAP financial measures do not have any standardized meaning and, therefore, may not be comparable with the calculation of similar measures for other companies. The Company includes as non-GAAP measures return on average capital employed, cash flow from operations, unit cash operating cost and total unit cost because they are key internal and external financial measures used to evaluate the performance of the Company.

All forward-looking statements are qualified by the cautionary note on the inside front cover of this report.

The Corporation's reserves disclosure and related information have been prepared in reliance on a decision of the applicable Canadian securities regulatory authorities under *National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities* (NI 51-101), which permits the Corporation to present its reserves disclosure and related information in accordance with the applicable requirements of the United States Financial Accounting Standards Board and the United States Securities and Exchange Commission. This disclosure differs from the corresponding information required by NI 51-101. If Shell Canada had not received the decision, it would be required to disclose (i) proved plus probable oil and gas reserves estimates based on forecast prices and costs and information relating to future net revenue using forecast prices and costs, and (ii) minable bitumen reserves estimates based on forecast prices and costs and information relating to future net revenue using constant and forecast prices and costs. The Corporation's internal qualified reserves evaluators prepare the reserves estimates.

Certain volumes have been converted to barrels of oil equivalent (BOE). BOEs may be misleading, particularly if used in isolation. A conversion of six thousand cubic feet of natural gas to one barrel of oil, as used in this report, is based on the energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Additional information relating to Shell Canada Limited filed with Canadian and U.S. securities regulatory authorities, including the Annual Information Form *and* Form 40-F, *can be found online under Shell Canada's profile at* ***www.sedar.com*** *and* ***www.sec.gov***.

Shell Canada reported an outstanding year in 2005 with record earnings of $2,014 million, or $2.44 per common share. This represents a significant increase of 56.6 per cent from the previous record of $1,286 million or $1.56 per common share in 2004. In 2005, strong appreciation in the share price over the course of the year resulted in a $173 million charge to earnings related to the Company's Long Term Incentive Plan (LTIP). However, this impact on earnings was more than offset by the use of non-capital losses available to the Company and proceeds from insurance settlements.

SELECTED ANNUAL FINANCIAL INFORMATION

Year ended December 31 ($ millions except per share data)	2005	2004	2003
Earnings	**2 014**	1 286	810
Total revenues	**14 394**	11 288	9 117
Total assets	**13 655**	10 906	9 613
Long-term debt[1]	**200**	1	2
Per common share (dollars)[2]			
Earnings – basic	**2.44**	1.56	0.98
Earnings – diluted	**2.41**	1.55	0.97
Cash dividends	**0.367**	0.313	0.273

[1] The long-term debt includes the variable interest entity, which was consolidated in 2005. See Note 6 to the Consolidated Financial Statements.

[2] Restated for June 2005 share split.

SUMMARY OF QUARTERLY RESULTS

(unaudited)	2005					2004				
	Quarter				Total	Quarter				Total
($ millions except as noted)	1st	2nd	3rd	4th	Year	1st	2nd	3rd	4th	Year
EARNINGS										
Revenues	**3 005**	**3 390**	**3 956**	**4 043**	**14 394**	2 514	2 640	3 058	3 076	11 288
Expenses	**2 453**	**2 665**	**3 310**	**3 180**	**11 608**	1 971	2 192	2 441	2 799	9 403
Earnings before income tax	**552**	**725**	**646**	**863**	**2 786**	543	448	617	277	1 885
Income tax	**135**	**199**	**189**	**249**	**772**	175	163	166	95	599
Earnings	**417**	**526**	**457**	**614**	**2 014**	368	285	451	182	1 286
SEGMENTED EARNINGS										
Exploration & Production	**131**	**114**	**157**	**263**	**665**	156	91	129	73	449
Oil Sands	**103**	**264**	**227**	**196**	**790**	96	96	173	13	378
Oil Products	**123**	**128**	**81**	**106**	**438**	118	110	114	109	451
Corporate	**60**	**20**	**(8)**	**49**	**121**	(2)	(12)	35	(13)	8
Earnings	**417**	**526**	**457**	**614**	**2 014**	368	285	451	182	1 286
PER COMMON SHARE (dollars)[1]										
Earnings – basic	**0.51**	**0.64**	**0.55**	**0.74**	**2.44**	0.44	0.35	0.55	0.22	1.56
Earnings – diluted	**0.50**	**0.63**	**0.55**	**0.73**	**2.41**	0.44	0.35	0.54	0.22	1.55
Dividend paid	**0.084**	**0.083**	**0.090**	**0.110**	**0.367**	0.074	0.073	0.083	0.083	0.313
Weighted average shares (millions)[1]	**825**	**825**	**825**	**825**	**825**	825	825	825	826	826
Dilutive securities (millions)[1]	**10**	**8**	**11**	**10**	**9**	6	6	6	7	6

[1] Restated for June 2005 share split.

The three major business units reported solid operational performances, capitalizing on the favourable economic conditions provided by high commodity prices and strong refining margins throughout the year. Earnings benefited in particular from a strong contribution by the Oil Sands business unit, record earnings from Exploration & Production (E&P) and record production overall. In the downstream business, Oil Products earnings fell slightly from the previous year's record as increased costs more than offset the gains from strong refining margins and improved light oil yields. The Corporate sector reported positive earnings of $121 million related to the use of non-capital losses available to the Company.

Earnings for the fourth quarter of 2005 were $614 million, more than three times the $182 million for the corresponding quarter in 2004 as production improved, and commodity prices and refining margins remained strong through the last three months of the year. Fourth-quarter earnings included a favourable adjustment of $65 million pertaining to the use of non-capital losses from the acquisition of an affiliated company in 2004 and a $27 million charge related to the LTIP.

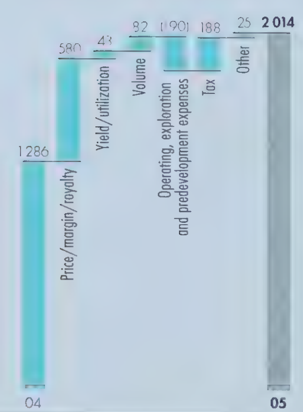
Fourth-quarter earnings reflected significant year-over-year improvements in E&P and Oil Sands, while Oil Products earnings for the fourth quarter were almost the same as the comparable period in 2004. Corporate reported a positive contribution to earnings of $49 million due to the use of non-capital losses.

The 2005 results delivered a strong return on average capital employed of 26.8 per cent. Cash flow from operations in 2005 was a record $3,056 million compared with $2,129 million the previous year.

In 2005, capital, exploration and predevelopment expenses reached a total of $1,715 million compared with $951 million in 2004. E&P capital expenditures in 2005 increased to $873 million from $451 million in 2004 mainly due to increased exploration and land acquisitions. In addition, two significant pipeline projects were completed to extend the life of existing gas plants and reduce future operating costs.

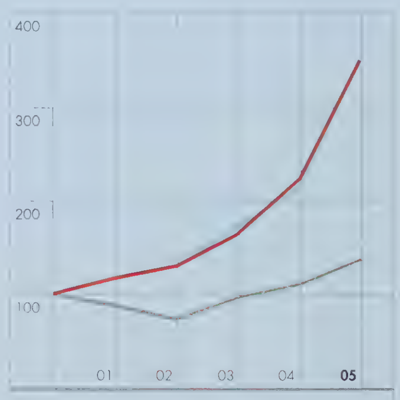
EARNINGS
($ millions)

Record volumes combined with high commodity prices and refining margins boosted 2005 earnings to $2 billion.



EARNINGS ANALYSIS
($ millions)

Strong commodity prices and refining margins plus record volumes helped offset rising operating costs in 2005.



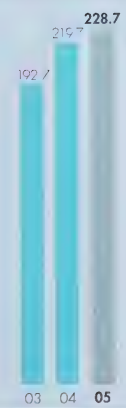
TOTAL SHAREHOLDER RETURN
(index value)
Shell
S&P/TSX Integrated Oil & Gas Index
S&P/TSX Composite Index

In 2005, Shell Canada continued to provide competitive returns, well above the TSX Composite Index.

At the end of 2005, gross proved natural gas reserves totalled 1,592 billion cubic feet (bcf) after production of 187 bcf, which compared with 1,595 bcf for 2004. The reserves additions included 184 bcf from extensions and discoveries and an additional nine bcf from an acquisition in the Burmis region of Alberta. The former included an additional 74 bcf for Tay River and a 52 bcf booking for the Company's early investment position in basin-centred gas (BCG). These gains were partially offset by nine bcf of net downward technical and economic revisions. The 2005 production of natural gas liquids was 14 million barrels. However, positive technical and economic revisions limited the decrease in gross proved reserves to only seven million barrels.

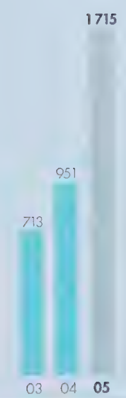
In 2005, gross proved minable bitumen reserves increased to 808 million barrels from 621 million in 2004. Drilling activity resulted in the reclassification of about 222 million barrels to the proved from probable category, offset by 35 million barrels of minable bitumen production. Total gross proved and probable minable bitumen reserves decreased by the 35 million barrels produced to 936 million barrels at the end of 2005.

In 2005, the Company rebooked 28 million barrels of gross proved bitumen reserves at Peace River. The United States Securities and Exchange Commission reserves reporting rules and related guidance prescribes the use of constant year-end pricing and costs to determine proved reserves. Canadian bitumen prices were low at year-end 2004 due to wide heavy oil market differentials and high condensate prices. As a result, the Company debooked all its Peace River bitumen reserves in 2004.



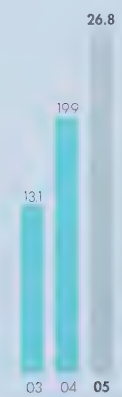
TOTAL HYDROCARBON PRODUCTION
(thousands of barrels of oil equivalent per day)*

A strong contribution from Oil Sands pushed total hydrocarbon production to a record high in 2005.



CAPITAL, EXPLORATION AND PREDEVELOPMENT EXPENDITURES
($ millions)

Investments in fuel quality and growth projects together with land acquisitions drove expenditures in 2005.



RETURN ON AVERAGE CAPITAL EMPLOYED
(per cent)

In 2005, return on average capital employed rose by more than one-third over 2004.

* See cautionary note on page 18.

Shell Canada's new development strategy for Peace River includes plans for a proposed expansion project. The 28 million barrels rebooked for 2005 is solely the reserves portion associated with existing wells and facilities and wells now being drilled. Engineering and regulatory work on the expansion will continue over the next two years before a final investment decision is made. Once that key project milestone is reached, the Company expects it will be able to book additional Peace River reserves.

A detailed explanation of Shell's reserves position appears on pages 86 to 89.

Shareholder Return

At the annual and special meeting of shareholders held April 29, 2005, the Company's shareholders approved a three-for-one share split, which took effect on the Toronto Stock Exchange June 21, 2005. Total shareholder return in 2005 was 59.3 per cent. In the fourth quarter, the Company's quarterly dividend was $0.11 per common share compared with $0.083 in the same period of 2004 (adjusted for the share split). Dividends paid for the year totalled $0.37 per common share, up from $0.31 per share in 2004.

Business Environment

During 2005, energy prices in North America – including crude oil and natural gas – reached unprecedented levels. The main reason for the increase was the tightness of supply in both the global oil and North American natural gas markets. While world oil demand continued to grow in 2005, albeit at a slower rate than in 2004, crude supply increased only marginally and spare production capacity was at historically low levels. In the continental natural gas market, consumption also continued to grow, but supply remained flat despite record drilling activity in both the United States and Canada. The pressure on the price of crude oil and oil products intensified with the significant outage in both oil and gas production capacity following the hurricane season in the U.S. Gulf of Mexico.

Crude oil prices reached record levels in 2005 as world demand increased and supplies dwindled. Increased output by the Organization of Petroleum Exporting Countries in 2005 could not fully compensate for supply disruptions resulting from damage caused by hurricanes in the U.S. Gulf of Mexico, conflict in the Middle East and labour strikes in Venezuela. Inventories of refined petroleum products in the United States remained low. In addition, growing demand in China and India helped push world oil prices to a record $70 US per barrel. Prices at year-end were $61.06 US per barrel compared with $43.45 US at year-end 2004. In turn, crude oil prices influenced natural gas and natural gas liquids prices.

The rapid rise in crude oil prices, low inventories in North America and a tight balance between supply and demand resulted in strong refining margins throughout 2005. Overall demand in Canada for oil products remained generally strong in the first half of the year but weakened during the final six months. In late August and September, the effects of hurricanes Katrina and Rita dominated the market. Panic buying in Eastern Canada, based on pricing rumours, caused operational and logistical difficulties.

Although the increased demand strained Shell's capacity, requiring the use of product allocations on a number of occasions, the Company maintained customer supplies. High product prices in the marketplace depressed demand for premium gasoline and intense competition, particularly in Ontario, compressed retail marketing margins.

In 2005, the average natural gas price in Canada was $8.71 Cdn per thousand cubic feet (mcf) compared with $6.52 per mcf in 2004. At year-end, the price was $10.05 per mcf. The Company realized an average plant gate price of $8.23 per mcf, an increase from $6.49 per mcf in 2004.

Natural gas liquids include ethane, propane, butane and condensate. Ethane supplies remained low throughout 2005, while demand for use in petrochemical products increased and prices for 2005 were closely aligned with natural gas prices. Both propane and butane prices rose sharply in 2005, as demand for these products increased. Condensate, which is used to dilute bitumen and heavy oil and as refinery feedstock, traded at a premium to the $56.56 per barrel average price of crude oil.

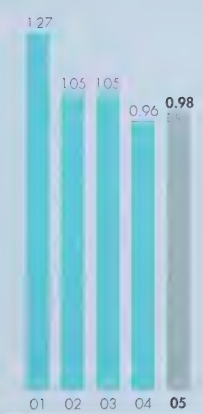
Strong demand in North America and internationally kept sulphur prices robust throughout 2005. Shell Canada remains the leading sulphur exporter in Canada and was able to capitalize on favourable market conditions by remelting 308,000 tonnes from existing sulphur blocks to add to current production.

Shell Canada believes that added business value from meeting the needs of its customers is best created by:

- achieving greater efficiency in the Company's use of energy and natural resources;
- proactively managing health, safety and environmental risks;
- benefiting local communities; and
- engaging with its stakeholders.

Shell applies the principles of sustainable development to both existing operations and new business planning.

The Company has documented its environmental and social performance in 2005 in its fifteenth annual Sustainable Development Report, which will be available in April 2006 in print and online at **www.shell.ca**.



TOTAL RECORDABLE INJURY FREQUENCY
(per 200,000 hours)

While the 2005 TRIF was good by industry standards, the increase from 2004 was disappointing.

MANAGING HEALTH, SAFETY AND THE ENVIRONMENT

Shell's attention to health and safety management gives priority to the safety and well-being of its employees, contractors and neighbours. The Company's main safety performance measure (total recordable injury frequency for employees and contractors) in 2005 was 0.98 injuries for every 200,000 hours worked. While there has been an overall improvement in safety performance over the last five years, the increase to 0.98 in 2005 from 0.96 in 2004 is disappointing. Considerable effort continues to go into embedding health and safety into the hearts and minds of all employees and contractors to complement Shell's extensive health, safety and environment standards and processes.

Recognizing that personal injury statistics alone do not necessarily indicate how the Company is managing its major hazards, Shell uses other measures and initiatives. For example, each business unit investigates potentially serious incidents so that corrective action can be taken before an incident occurs. Management has also introduced "Learning from Incidents," a process where key findings for actual or potential serious incidents are shared with appropriate groups within Shell. This new process is expected to help reduce human error and the number of equipment and procedural failures.

The Oil Products Ultra Low Sulphur Diesel Project at Montreal East Refinery and Scotford Refinery received the President's Safety Award in 2005 in recognition of its outstanding safety performance and overall approach to safety management.

The Hon. Ralph Klein, Premier of Alberta (centre), and Shell Canada's President and Chief Executive Officer Clive Mather (left) congratulate Mick Boiselle, a Shell Spirit of the Future Award winner.

Shell Canada continues to make progress towards its voluntary greenhouse gas emissions reduction target of six per cent below 1990 levels by 2008 for its base business (E&P and Oil Products), mainly through energy efficiency improvements. In 2005, greenhouse gas emissions from the base business were 7.6 million tonnes, 217,000 tonnes less than in 2004 and 5.6 per cent below the 1990 level. Energy efficiency has improved by 12 per cent since 2000.

BENEFITING CANADIANS

In 2005, Shell Canada donated almost $8 million to not-for-profit organizations across the country to support environmental and educational programs as well as local communities where employees, retirees and marketing associates live and work.

Shell Canada matched funds raised by the employees and retirees of the Company and its affiliates for a record donation of $4.2 million to the United Way of Calgary and Area. The total amount was the largest single United Way contribution in Alberta's history. It represented 10 per cent of the Calgary and Area 2005 campaign goal and, for the third consecutive year, was the largest ever United Way contribution from an organization headquartered in Western Canada. The Company matched employee and retiree donations for a total contribution of $5.2 million across Canada.

In 2005, Shell celebrated Alberta's centennial with the "Shell Spirit of the Future Awards" supported by a media alliance. This province-wide program recognized 34 young Albertans, ages 16 to 25, who contribute to Alberta's future through their educational and volunteer pursuits. Shell awarded each winner a $5,000 scholarship towards postsecondary education and donated $5,000 to each not-for-profit organization where they volunteer. The winners also appeared in their own television vignette, which was broadcast across Alberta in the fall.

In 2005, the Shell Environmental Fund (SEF) celebrated 15 years of providing grants to Canadians who want to improve or protect their local environment. Launched in 1990, the SEF had granted more than $11.5 million to over 3,900 environmental projects across the country by the end of 2005. Grants support projects such as habitat restoration, waste reduction and recycling programs, educational initiatives and beach cleanups.

Shell Canada's reputation as an employer of choice is critical for employee retention and recruitment.

ENGAGING WITH STAKEHOLDERS

Shell recognizes that stakeholder engagement is essential if the Company is to understand the environmental and social issues surrounding the operations and growth of its businesses. Shell representatives continue to work with governments, industry organizations, non-governmental organizations, First Nations and local communities throughout project planning and operations.

The Mackenzie Gas Project (MGP) is an example of the importance and challenges of dialogue and engagement. After halting project execution activities earlier in the year, the MGP proponents, including Shell Canada, agreed in November 2005 to begin the regulatory approval process in early 2006. The agreement to proceed was the result of patient negotiation between a variety of stakeholders. It was an important step forward for this large, multibillion-dollar project, which is expected to provide employment and business opportunities and new infrastructure to local, mostly Aboriginal communities.

PEOPLE

For the sixth consecutive year, Mediacorp Canada Inc. selected Shell Canada as one of Canada's Top 100 Employers and one of Alberta's Top 20 Employers. Shell Canada's reputation as an employer of choice is critical for employee retention and recruitment, especially with the shortages in a number of skill areas now facing the oil and gas industry.

Given its growth initiatives in all business units, the Company considers recruiting and retaining new graduates and experienced employees crucial to its future success. To support these efforts, Shell has strengthened the competitiveness of its employment package for current and prospective employees. Shell's employee value proposition rests on three balanced components:

- a strong, competitive compensation package that includes pay linked to results;
- careers that offer exciting job opportunities, and continuous learning and development; and
- a work environment that emphasizes valuing and promoting diversity, ethics and personal responsibility.

Shell has also introduced a comprehensive program to integrate new employees into the Company.

Shell Canada's management and board of directors are committed to the highest standards of corporate governance

Corporate Governance

Shell Canada's management and board of directors are committed to the highest standards of corporate governance. The Company's principles, policies and practices, which are reviewed regularly to enable Shell and its board to address evolving regulatory requirements and best practices, provide a solid framework for fulfilling this commitment.

A number of key developments occurred in 2005. The board appointed an independent Lead Director to complement the role of the Chairman of the Meetings of the Board and adopted a policy on director independence. The board has added two new committees, each comprising five independent directors, which will focus on the more detailed activities in two important areas: the Company's systems and programs for the management of its health, safety, environment and social responsibilities, and pension administration, respectively. These areas were previously overseen by the full board.

The board and its committees of independent directors continue to meet separately from members of Shell management at each scheduled meeting. Independent directors also hold separate sessions without the presence of management and non-independent directors.

Internal Controls

Shell Canada promotes strong financial, business, disclosure and anti-fraud controls and procedures in its business processes and maintains high standards for integrity in financial reporting. Under Section 404 of the *Sarbanes-Oxley Act* (SOx), management must report on the effectiveness of internal controls over financial reporting. Shell believes it is well-positioned to file for year-end 2006, as will be required by the United States Securities and Exchange Commission.

The Company's Chief Executive Officer and Chief Financial Officer have filed annual certifications for the last four years in compliance with SOx Section 302 and similar certifications required by Canadian regulation. These officers believe that Shell Canada's disclosure controls and procedures operated effectively in each of these years and for the year ended December 31, 2005.

Risk Management

Each year, Shell Canada assesses areas of risk and decides how to mitigate them to acceptable levels. The board of directors reviews the identified risks, which are consolidated for the overall Company. The areas of risk that apply to the entire organization are largely related to the unprecedented growth opportunities and include major project execution; organizational capability; control framework for growth; material and equipment shortages; and community relations. The Company also monitors risks associated with commodity prices and operational reliability. Each business unit discusses the risks specific to its operations in its own section of this report.

During 2005, the Company strengthened all elements of the employee value proposition to ensure competitiveness.

ORGANIZATIONAL CAPABILITY

Future growth will depend on the Company's ability to attract, develop and retain key people, including both skilled trades people in project construction and employees for ongoing operations. Shell Canada has established recruitment targets for new graduates and experienced staff. During 2005, the Company strengthened all elements of the employee value proposition to ensure competitiveness. Shell also introduced a program to promote a comprehensive and consistent introduction to the Company's policies and control framework for all new employees. Despite these initiatives, the Company is concerned about its ability to find sufficient people and skills in the current environment.

MAJOR PROJECT EXECUTION

The Company is pursuing a number of concurrent large-scale projects, which could be constrained by the ability to attract enough people, complete engineering and procure materials. Any or all of these constraints could increase costs and delay schedules. Mitigation measures include assembling experienced project teams who share best practices and lessons learned through project look-backs. Other measures include an integrated project management system with detailed front-end engineering and execution planning, dividing projects into more manageable phases to promote continuity of resources, developing efficient construction techniques and making strategic long-term alliances with key suppliers and contractors.

COMMODITY PRICES

Fluctuations in the price of crude oil, natural gas and petroleum products have a significant bearing on the Company's financial results, as shown in the table below. Shell mitigates this risk by using conservative price premises for all capital projects and budgets. For its Oil Products business, the Company also uses limited hedging to reduce exposure to price swings. In general, Shell Canada does not hedge in light of its conservative premises and strong balance sheet.

2005 OPERATING EARNINGS SENSITIVITIES (after-tax annualized)[1]

		Increase/(Decrease)
EXPLORATION & PRODUCTION		
Natural Gas	10-cent US increase per million BTUs[2] (Henry Hub)	$ 9 million
Condensate	$1 US increase per barrel (West Texas Intermediate)	$ 3 million
Bitumen	$1 US increase per barrel (West Texas Intermediate)	$ 2 million
Sulphur	$1 Cdn increase per tonne	$ 2 million
Foothills natural gas production	Increase of 10 million cubic feet per day	$ 10 million
OIL PRODUCTS		
Light oil sales margin	1/4-cent Cdn increase per litre	$ 25 million
Natural Gas	10-cent US increase per million BTUs[2] (Henry Hub)	$ (3) million
OIL SANDS		
Crude Oil	$1 US increase per barrel (West Texas Intermediate)	$ 28 million
Natural Gas	10-cent US increase per million BTUs[2] (Henry Hub)	$ (2) million
Equity Production	Increase of 1,000 barrels per day	$ 13 million
SHELL CANADA EXCHANGE RATE	1-cent improvement in $Cdn vs. $US	$ (27) million

[1] Sensitivities (eg: Henry Hub, West Texas Intermediate) are calculated independently and assume other market variables remain constant.

[2] BTUs: British thermal units.

CONTROL FRAMEWORK FOR GROWTH

A robust control framework is critical to managing project timing and costs. Shell Canada has confidence in its present processes and continues to look for ways to strengthen its controls, improve its management information systems and enhance employee training.

MATERIAL AND EQUIPMENT

The increase in activity and competing projects within the oil and gas industry could make it more difficult to acquire critical goods and services, which would increase the lead times on orders, drive up costs and, potentially, disrupt project schedules. Shell monitors current market conditions and bottlenecks in the supply chain, and uses best practice procurement strategies. The Company also liaises with Royal Dutch Shell, leveraging its experience and buying power.

OPERATIONAL RELIABILITY

Operating interruptions at any of Shell's operating facilities could adversely affect the Company's financial results and its ability to meet its commitments to customers. Mitigation measures include regular maintenance programs, continuing asset integrity reviews, and the retention of highly trained and experienced personnel. The diverse nature and locations of Shell's operating facilities reduce the risk of more than one facility experiencing interruptions at the same time.

COMMUNITY RELATIONS

Many of the Company's planned projects depend on support from local communities, the loss of which could result in escalating demands, project delays and spiralling costs. To meet project objectives for Oil Sands expansion, Shell has negotiated a long-term benefits agreement between the Athabasca Tribal Council, the Alberta and federal governments, and others in the oil sands industry. For the Mackenzie Gas Project, Shell has undertaken to provide opportunities for local communities to participate in project planning by taking a proactive approach to engagement and maintaining a regular presence wherever Shell conducts its activities.


NABORS

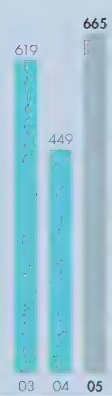
In 2005, Exploration & Production (E&P) delivered record earnings of $665 million compared with $449 million in 2004.

This result was mainly due to strong commodity prices, with a contribution from increased volumes at Shell's Peace River in situ bitumen complex and new production from basin-centred gas (BCG), which helped offset increased expenses and lower volumes due to natural field decline, plant turnarounds and flooding in the Foothills of Alberta. Earnings in 2005 reflected positive tax adjustments of $39 million and an insurance settlement of $12 million, offset by a charge of $50 million related to the Long Term Incentive Plan (LTIP).

During 2005, the Company's E&P business acquired almost 200,000 net acres at Crown land sales in Alberta and British Columbia as well as a 20 per cent interest in the Orphan Basin offshore Canada's east coast through a farm-in of eight exploration licences in March. Also in 2005, E&P hired almost 150 new employees to support its growing business.

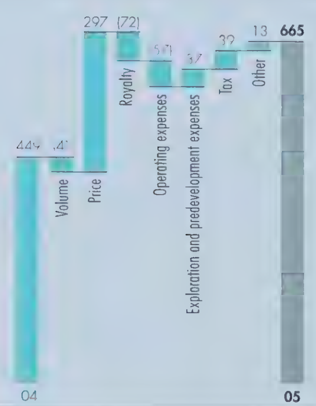
The business unit's return on average capital employed for 2005 was 37.2 per cent, up from 28.3 per cent in 2004.

E&P earnings in the fourth quarter of 2005 were $263 million, an increase of $190 million from $73 million for the corresponding period in 2004. Gains from strong commodity prices combined with lower exploration and lower LTIP charges more than made up for higher operating costs. A $32 million charge related to predevelopment expenses on the Mackenzie Gas Project reduced fourth-quarter results in 2004. LTIP charges were $8 million in the fourth quarter of 2005 compared with $24 million for the same period of 2004.



EXPLORATION & PRODUCTION EARNINGS
($ millions)

Strong commodity prices and production resulted in record earnings in 2005.

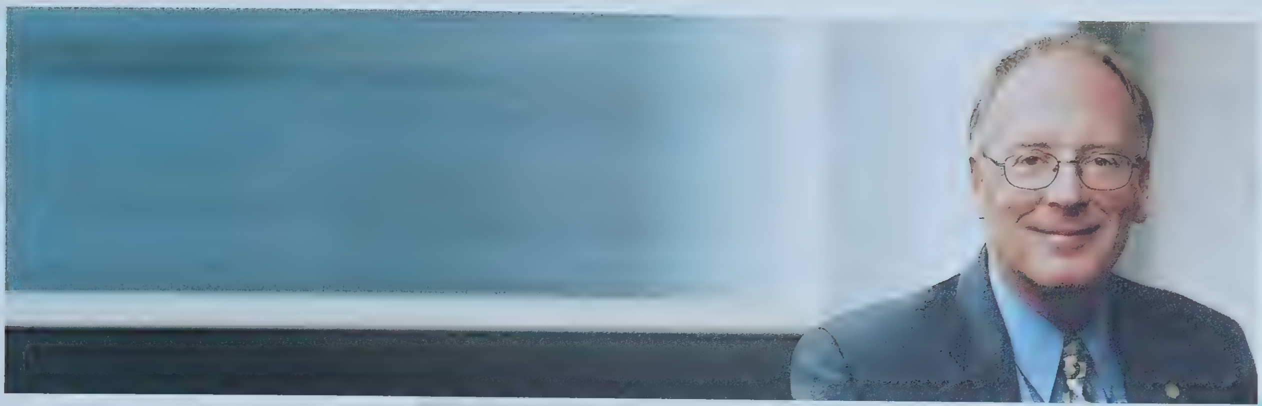


EXPLORATION & PRODUCTION EARNINGS ANALYSIS
($ millions)

Strong commodity prices and new production from Tay River and basin-centred gas helped offset rising costs in 2005.

EXPLORATION & PRODUCTION UNIT COSTS
($ per barrel of oil equivalent)

Increased processing at third party plants and plant turnaround and LTIP expenses resulted in higher unit operating costs in 2005.



H. IAN KILGOUR
Senior Vice President, Exploration & Production

EXPLORATION & PRODUCTION HIGHLIGHTS

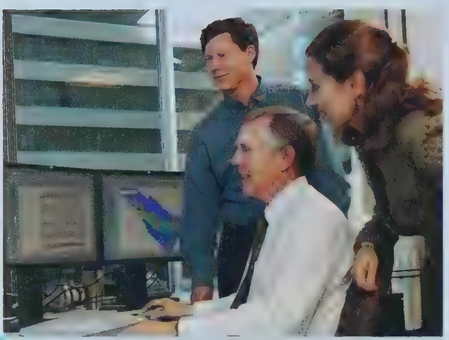
($ millions except as noted)	**2005**	2004	2003
Revenues	**2 611**	2 198	2 113
Earnings	**665**	449	619
Capital employed	**2 052**	1 523	1 648
Capital, exploration and predevelopment expenditures	**873**	451	385
Return on average capital employed (%)	**37.2**	28.3	37.3

Total production of natural gas in 2005 was 512 million cubic feet per day (mmcf/d) compared with 540 mmcf/d in 2004. Total natural gas production for the fourth quarter of 2005 was comparable to the same period of 2004, in spite of plant turnaround activities that extended into October. Increased fourth-quarter production from the Sable Offshore Energy Project (SOEP) along with new production from Tay River and BCG gas more than made up for natural field decline. As a result, gas production was higher at year-end 2005 than at year-end 2004.

Production of natural gas liquids fell in 2005 to 38,600 barrels per day (bbls/d) from 40,300 bbls/d in 2004 due to natural field decline in Shell's liquids-rich Caroline field. Peace River's infill program resulted in an increase in bitumen volumes to an average 8,900 bbls/d from 8,100 bbls/d.

The Foothills business operates mainly in southern and central Alberta with four Shell-operated gas plants and a number of producing fields. E&P's Foothills operations now include production in northeast British Columbia.

The Foothills business remains the largest contributor to profit in E&P, with 2005 sales gas production averaging 391 mmcf/d of natural gas, which accounts for 76 per cent of Shell's total natural gas production. In addition, Foothills produced 21,100 bbls/d of natural gas liquids (ethane, propane and butane), 11,200 bbls/d of



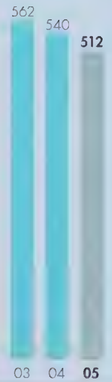
Foothills geophysicists David Haugseth (sitting), Cameron Luck and Carly Grimsen Seligman work together on the kind of seismic processing and interpretation that led to the discovery of Shell's Tay River well.

condensate and 5,300 tonnes per day of sulphur. This compares with 2004 figures of 415 mmcf/d sales gas produced, 23,300 bbls/d natural gas liquids, 12,700 bbls/d condensate and 5,600 tonnes per day of sulphur. Although annualized volumes were lower than in 2004, the volume of Foothills sales gas produced at year-end was about two per cent higher than at the beginning of the year.

Shell has 75 per cent ownership in the Tay River well southwest of Rocky Mountain House in central Alberta, which was a major discovery in 2004. Tay River began production in May 2005 and initial results were encouraging. The installation of larger production tubing in October increased Tay River well production to a rate of 95 mmcf/d of raw gas at year-end, giving it the highest flow rate of any natural gas well in Canada. Two more wells are planned for 2006, one to delineate the original discovery and the other to test a new structure.

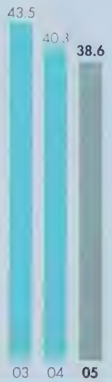
The 2005 Foothills development program totalled $292 million and achieved significant progress in optimizing existing infrastructure. A pipeline connecting the Moose Mountain natural gas field to Shell's Jumping Pound gas plant was completed in May and construction of Jumping Pound's enhanced sulphur recovery unit was completed in October. This project incorporated new technology to recover more sulphur from natural gas, which will reduce sulphur dioxide emissions to the environment. The pipeline connecting the Limestone field to Shell's Caroline gas plant started flowing in July. This pipeline will also connect to the Panther field in the second quarter of 2006. These projects will help maintain significant long-term volumes of raw gas to the gas plants and provide additional processing options for the fields.

The planning phase of the Waterton gas plant optimization project continued in 2005 and a decision on whether or not to proceed will be made in 2006. The project team is evaluating the reconfiguration of the facility to improve cost structure and maximize utilization.



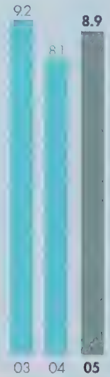
GROSS PRODUCTION OF NATURAL GAS
(millions of cubic feet per day)

Full-year 2005 volumes fell slightly from the prior year, but were higher at year-end versus year-end 2004.



GROSS PRODUCTION OF NATURAL GAS LIQUIDS
(thousands of barrels per day)

Natural field decline in the liquids-rich Caroline field reduced overall production in 2005.



GROSS PRODUCTION OF BITUMEN
(thousands of barrels per day)

Investment in additional wells at Peace River resulted in increased bitumen volumes in 2005.

In August 2005, Foothills acquired all the assets of Hunt Oil of Canada Inc. in the Waterton area, which included three producing wells in the Burmis field and a gathering system linked to Shell's Waterton plant.

The joint venture drilling program continued in the Panther area and the other participant has now earned the right to 50 per cent of all future investments. Three new Panther wells were tied in during 2005 and two additional wells were drilling at year-end. Further drilling is planned for future years.

In 2005, Foothills continued to explore in both northeast British Columbia and Alberta with a $97 million exploration program, up from $61 million in 2004. These expenditures included significant land purchases and participation in six exploration wells. Four of these wells did not prove commercially viable and two were still in progress at year-end. Foothills plans similar exploration expenditures in 2006.

Unconv

The Unconventional Gas business grew significantly throughout 2005, with capital investments of $306 million on land acquisitions, seismic, drilling operations and tie-in of new wells. Unconventional Gas focuses on basin-centred gas and coal bed methane (CBM) opportunities. The BCG team explores reservoirs with low permeability. The CBM group explores for gas found in coal deposits.

Shell Canada's basin-centred gas activities are focused in the Chinook Ridge region of the border between Alberta and British Columbia.

BASIN-CENTRED GAS

The Company's BCG activities are focused in the Chinook Ridge region of the Deep Basin area of Western Canada straddling the Alberta/British Columbia border. Initial results of the drilling program have been encouraging. At year-end, five wells were either drilling or being tested and six wells were producing. A lack of processing infrastructure limited production to an average annual rate of 2.4 mmcf/d (17 mmcf/d in December). Presently, there is insufficient processing capacity in the Chinook Ridge area due to the high level of industry activity in the region. In response, the Company is evaluating possible infrastructure solutions, including building a Shell-owned natural gas plant. The drilling program will be expanded in 2006. In 2005, Shell more than tripled its existing BCG land position to provide a framework for future growth.

COAL BED METHANE

In 2005, the CBM team focused on three areas: Sparwood, southeast British Columbia; Ram River, Foothills of Alberta; and Klappan, northwest British Columbia. During 2005, Shell conducted test well programs at Sparwood and Ram River. The results were not sufficiently encouraging to warrant further exploration in these areas. Shell has postponed the start of the next phase of its test well program in Klappan to allow time for further public consultation with local communities. At present, there are no estimated reserves or commercial production related to CBM.

Frontier

SABLE OFFSHORE ENERGY PROJECT

Shell Canada's SOEP interests in the shallow water offshore Nova Scotia continue to provide significant cash and earnings. Additional development of the South Venture field in 2005 helped offset natural production decline from other SOEP fields. Production of sales gas averaged 119 mmcf/d (Shell share) in 2005 compared with 125 mmcf/d in 2004. Production from the South Venture field also helped increase SOEP condensate volumes, which averaged 4,100 bbls/d (Shell share) compared with 2,500 bbls/d in 2004.

The second and third wells in the South Venture field came on stream in the second quarter of 2005. An additional infill well in the Venture field was drilled in the second half of the year and was producing by year-end. Drilling began on the third well in the Alma field in February 2006 and first production is expected by mid-year.

Construction of the field compression project continued in 2005, with startup expected late 2006. This project will help offset natural field decline and increase ultimate recovery from SOEP.

OTHER EAST COAST INTERESTS

In addition to SOEP, Shell holds interests in the shallow water Sable Basin and in the deep water offshore Nova Scotia. Although Shell continues to evaluate opportunities, there are no plans for more exploration activities in these areas.

In 2005, Shell farmed into a 20 per cent interest in eight exploration licences in the Orphan Basin located in the deep water region offshore Newfoundland and Labrador. A three-dimensional seismic program took place in 2005 and drilling of the first exploratory well in the basin is planned for 2006.

NORTHERN CANADA

In November 2005, the proponents of the Mackenzie Gas Project, including Shell Canada, advised the National Energy Board that they were ready to proceed to public hearings on the proposed Mackenzie Valley Pipeline project. The decision was taken following assurances by stakeholders that several key issues could be resolved. The issues included clarification of the regulatory review process, negotiating benefits and access agreements with northern Aboriginal groups, and developing the necessary fiscal framework for the project. The proponents had halted project execution in April 2005 due to insufficient progress in these key areas.

Pre-hearing planning meetings with northern communities started in December 2005 and the regulatory process is expected to continue throughout 2006. A final decision to proceed with the project is subject to obtaining the necessary regulatory approvals and assessing any conditions attached to those approvals. It will also depend on a number of other factors, such as the final terms of benefits and access agreements, agreement on fiscal matters, natural gas markets, project costs and the level of shipping commitments on the pipeline.

Kim Johnson, Environment and External Affairs Coordinator for the Frontier, Northern Development group (sitting), and Paul Davies, the group's Regulatory, Integration and Regulatory Approvals Coordinator, consult with Mary Henderson, Senior Counsel for E&P, as they prepare for public hearings on the Mackenzie Gas Project.

In 2005, bitumen production from Peace River averaged 8,900 bbls/d compared with 8,100 bbls/d in 2004. The increase was attributable to seven infill wells that came on stream during the year. In addition, 32 wells (two pads) are drilling and expected to come on stream in the second half of 2006. Shell expects these wells to increase production to the plant's current capacity of 12,000 bbls/d.

Effective January 1, 2006, the Peace River business was transferred to the Oil Sands business unit and future plans are discussed in that section of this report. Synergies between the two are expected to provide future opportunities for reduced costs and larger-scale heavy oil integration.

Tracy Fummerton and Ray Carlyon of Shell's Jumping Pound gas plant inspect construction progress on the enhanced sulphur recovery unit, which will reduce sulphur dioxide emissions.

In 2005, E&P reported 1.29 recordable injuries for every 200,000 hours worked compared with a rate of 1.16 in 2004. Although this performance was strong given the number and scope of major projects that were completed in 2005, there are still opportunities for improvement. The investigation of circumstances surrounding incidents with a high potential for injury and near misses provides a wealth of information. Sharing what is learned within E&P and throughout the Company will drive improvement towards the goal of zero incidents.

A key commitment by E&P is to reduce the environmental impacts of its operations and development activities through initiatives such as enhanced sulphur recovery at the Jumping Pound gas plant and the drive for energy efficiencies through field projects.

E&P's commitment to sustainable development includes public consultation efforts that regularly exceed regulatory requirements. The business works with governments, non-governmental organizations, industry associations and local communities as well as individual landowners and community residents with respect to new projects and ongoing operations. One goal is to understand their concerns and negotiate mutually acceptable solutions to conflicting needs. Shell often takes a leadership role in supporting regional, multi-stakeholder synergy groups and looks for ways to reduce the potential impact of E&P activities while creating opportunities for local benefit.

All E&P operating sites are registered to a global ISO 14001 standard of environmental management, which requires demonstrated compliance with environmental legislation and continuous improvement in environmental performance. The certificate was reregistered in 2005.

Looking Forward

E&P's strategy in 2006 is to capitalize on current projects to increase Shell's natural gas production volumes and reserves while maintaining a solid operational base. In E&P's largest-ever capital investment program, key goals include:

> growing production volumes and enhancing future recovery in the Foothills area of Western Canada;

> completing the SOEP field compression project to help sustain production in the current fields;

> pursuing unconventional gas opportunities with a primary focus on growing basin-centred gas production. This includes evaluating and drilling the new land parcels acquired in 2005 and building necessary infrastructure for future processing; and

> completing the regulatory hearings on the Mackenzie Gas Project.

2006 Capital and Exploration Investment

E&P's planned investment program for 2006, which now excludes Peace River, is $1,010 million, of which $308 million will support exploration activities and $655 million is for development. The capital, exploration and predevelopment expenditures totalled $873 million in 2005, including $75 million for Peace River. About 50 per cent of the E&P program will sustain natural gas production levels in the Foothills area of Western Canada and at SOEP. The balance of the program is mainly focused on growth opportunities, including $404 million for unconventional gas and about $47 million for predevelopment expenses to advance the Mackenzie Gas Project regulatory process.

Risk Management

ORGANIZATIONAL CAPABILITY

With oil and gas prices at record levels, the industry is experiencing increased growth in drilling and exploration activities. This, in turn, has resulted in an industry-wide shortage of skilled people, specifically for technical and project management roles, which will make it challenging to implement E&P's aggressive 2006 investment plan. The E&P business is proactively addressing issues of recruitment, compensation and retention.

PROCESSING CAPACITY FOR FUTURE DEVELOPMENT

The Company does not have sufficient infrastructure to support E&P's activities as they expand north into Alberta and west into British Columbia. Gaining access to third party gathering systems and processing capacity remains difficult. Shell is actively pursuing options to ensure reliable infrastructure alternatives to meet growing capacity into the future.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In its second full year of integrated operations, Oil Sands reported record earnings of $790 million compared with $378 million in 2004 due to higher volumes and prices.

This represented 39 per cent of the Company's overall earnings, a significant contribution from this relatively new business. The earnings increase also reflected higher proceeds from insurance settlements in 2005, offset by higher Long Term Incentive Plan (LTIP) charges and smaller positive tax adjustments.

The 2005 earnings included $82 million related to the final insurance settlement for the January 2003 fire at the Muskeg River Mine. Earnings also included a charge of $29 million related to the LTIP. Revenues totalled $3,148 million, an increase of 51.9 per cent over $2,072 million in 2004. Oil Sands generated $1,388 million of cash flow from operations in 2005 compared with $686 million in 2004. Capital expenditures totalled $343 million in 2005.

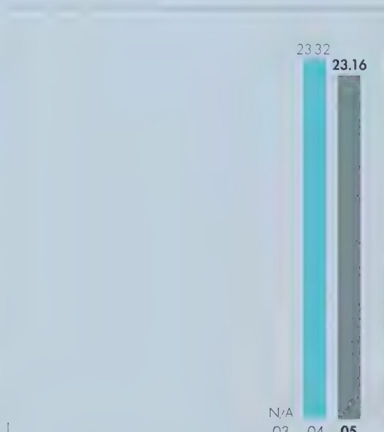
Oil Sands earnings in the fourth quarter of 2005 were $196 million, which was a significant increase over the $13 million reported for the corresponding period in 2004 when planned and unplanned maintenance activities disrupted operations. The comparative improvement between the fourth quarter 2005 and the fourth quarter 2004 was due to the operational disruptions in 2004 and increased production, higher prices and lower unit costs in 2005. Fourth-quarter 2005 earnings included a $5 million after-tax charge related to the LTIP compared with $11 million for LTIP in the final quarter of 2004.

OIL SANDS EARNINGS
($ millions)

Increased volumes and high crude oil prices resulted in record 2005 earnings for Oil Sands.

OIL SANDS EARNINGS ANALYSIS
($ millions)

Strong oil prices combined with record production more than offset rising costs in 2005.



OIL SANDS UNIT CASH OPERATING COST ($ per barrel of oil equivalent)

High fuel, labour and material costs in 2005 limited improvement in unit costs.

BRIAN E. STRAUB
Senior Vice President, Oil Sands

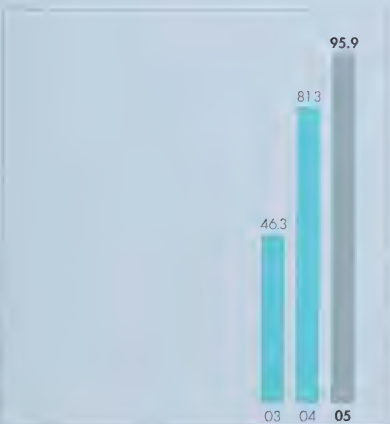
OIL SANDS HIGHLIGHTS

($ millions except as noted)	**2005**	2004	2003
Revenues	**3 148**	2 072	906
Earnings	**790**	378	(142)
Capital employed	**2 519**	2 860	3 092
Capital expenditures	**343**	179	123
Return on average capital employed (%)	**29.4**	12.7	(4.4)

In 2005, high crude oil prices had a positive effect on the Oil Sands business as Shell Canada realized an average selling price of $57.55 per barrel on sales of 50 million barrels including blended stock. The differential between the price realized and the price of Edmonton light crude remained wide due to continued high market differentials for heavy oil in a high commodity price environment.

Unit cash operating costs in 2005 were $23.16 per barrel, slightly lower than the $23.32 per barrel in 2004. Exceptionally high prices for natural gas and increased costs for labour and materials were major factors affecting unit costs.

Both the Muskeg River Mine and the Scotford Upgrader reported strong operational performances in 2005.



OIL SANDS GROSS BITUMEN PRODUCTION *(Shell share)*
(thousands of barrels per day)

Improved reliability resulted in record bitumen production for the Athabasca Oil Sands Project in 2005.

MUSKEG RIVER MINE

In 2005, the main focus at the mine was operational excellence. All areas of operations at Muskeg River Mine concentrated on achieving excellence in mine reliability, energy use, costs and safety, which resulted in consistent production and improved reliability. The average total bitumen production for the year was 159,900 barrels per day (bbls/d), which was above the design rate of 155,000 bbls/d and compared with 135,500 bbls/d in 2004. The mine achieved record production in 2005, producing 35 million barrels of bitumen (Shell share) compared with 30 million barrels in 2004.

In late February 2006, a tear in the conveyor belt that carries ore from the crushers in the mine to the bitumen extraction plant reduced operations to a single train at both the mine and the upgrader. Pre-installation work to replace the belt began immediately. Initial expectations were that installation of the new conveyor belt will require a complete shutdown of the mine in late March and is expected to take up to two weeks.

The Company's share of bitumen production in the fourth quarter of 2005 averaged 106,800 bbls/d compared with 65,900 bbls/d in the corresponding quarter of 2004 when operations were restricted to a single train. Total bitumen production for the Athabasca Oil Sands Project (AOSP) reached a new record in the fourth quarter of 2005, averaging 178,000 bbls/d.

Jean-Luc Gagné, froth treatment Operations Manager at the Muskeg River Mine, stands in front of the solvent recovery unit used in the froth treatment process.

SCOTFORD UPGRADER

The Scotford Upgrader's reliability improved significantly in 2005, largely due to the focus on operations and enhanced integration between the mine and the upgrader. Unplanned maintenance in 2004 continued to affect production in the first quarter of 2005. Then, in mid-March 2005, a valve failure in Train 1 and a temperature variance in the exterior wall of one of the residue hydrocrackers forced a shutdown of one train at the upgrader. After resumption of full operations in early April, average production at the upgrader consistently exceeded design capacity. Reliability improvements overall resulted in higher production at the upgrader, including a new production record of 184,100 bbls/d in November 2005. In September 2005, production was cut back to accommodate the reduced availability of third party hydrogen to the upgrader. This cutback, in turn, allowed minor planned maintenance at both the Scotford hydrogen plant and the Muskeg River Mine cogeneration facilities. A planned maintenance shutdown of one train at the Scotford Upgrader in the third quarter of 2005 was deferred until 2006 when the upgrader will undergo its first major planned turnaround.

Effective January 1, 2006, Shell Canada's Peace River in situ bitumen business became part of Oil Sands and future reporting will include Peace River.

Oil Sands operating performance in 2005 demonstrated that Shell Canada has a solid, reliable base business and proven technology from which to expand this business. The Company estimates it has more than 6.5 billion barrels of recoverable bitumen in its Athabasca leases, excluding new leases acquired in 2005, which are yet to be fully assessed. These resources support the Company's long-term plans to increase AOSP total production to more than 500,000 bbls/d. To achieve this goal, Oil Sands will concentrate on continued operational excellence, production optimization and debottlenecking of existing facilities, and profitable expansion using a continuous construction strategy. Continuous construction would expand production in a series of "building blocks," each of approximately 100,000 bbls/d.

In April 2005, Shell Canada filed regulatory applications to increase production capacity at both the Muskeg River Mine and Scotford Upgrader. Regulatory approval is expected in 2006. If granted, this approval combined with the previous approval for Jackpine Mine would enable Shell Canada to advance mining developments on all of Lease 13 and Lease 90.

The scope of the first AOSP expansion includes construction of common infrastructure such as pipelines and utility systems, which will be sized to support the long-term production goal of more than 500,000 bbls/d. Front-end engineering is on track and the Company has selected engineering contractors for both the mine and upgrader expansion projects.

Jessica Norgaard, Senior Process Technologist at Shell Canada's Calgary Research Centre, stands in the Dean Stark Laboratory where a solvent extraction procedure determines the amount of bitumen and water in, for example, an oil sands core sample.

The final investment decision for the first AOSP expansion (mine and upgrader) is expected in 2006. Construction at both facilities is expected to start in the second half of 2006 with completion targeted for late 2009. Front-end engineering work on future Oil Sands expansions has also begun, including conceptual design, with subsequent engineering work to progress in 2006. Gasification facilities associated with additional upgrading are also being evaluated as part of this front-end development work.

With the strategic decision to pre-build infrastructure for future expansions, Shell Canada has taken an important step toward its goal of more than 500,000 bbls/d of total bitumen production at the AOSP. As part of its focus on long-term growth, Shell acquired seven additional Athabasca oil sands leases in Crown land sales during 2005. Although still under evaluation, this land offers potential future expansion beyond 500,000 bbls/d. The other joint venture parties in the initial Muskeg River Mine development have the option to participate in the future development of Shell's other existing Athabasca oil sands leases. Shell Canada, in turn, has the option to participate in leases purchased by the other joint venture parties.

Expansion of the Peace River operation is in the front-end engineering phase and filing of the regulatory application is expected in 2006. Shell anticipates that the Carmon Creek project, which is the first phase of expansion, could increase total bitumen production to 30,000 bbls/d. The final investment decision on Carmon Creek is planned for 2007, with expected production startup in 2009. Shell Canada's current Peace River leases, which are estimated to contain about seven billion barrels of bitumen in place, have the potential to support development in the order of 100,000 bbls/d.

Health, Safety, Environment and Sustainable Development

Oil Sands continued its focus on safety performance, maintaining an emphasis on individual responsibility for the task at hand. As a result, the business recorded a lost-time injury frequency rate of 0.4 per 200,000 hours worked. Muskeg River Mine achieved four million hours without a lost-time incident, while the Scotford Upgrader reported two million hours without a lost-time incident in 2005. Oil Sands total recordable injury frequency rate was 0.96.

The AOSP continues to integrate sustainable development into the life cycle of the project, from design and operations through reclamation.

J.J. (Janet) Zazubek, an environment co-op student who worked at the Muskeg River Mine for part of 2005, holds a large wooden raptor designed to scare birds away from the mine site.

Oil Sands is investigating technologies to further reduce carbon dioxide (CO_2) emissions from its operations. In addition, the AOSP has undertaken several CO_2 capture and sequestration studies to evaluate cost-effective solutions to manage CO_2 emissions.

By expanding its tree-planting program to include the Fort McMurray region in 2005, the AOSP is making progress toward its emissions reduction target. In partnership with Tree Canada Foundation, approximately 12,000 white spruce and 4,000 aspen trees were planted in June 2005. It is estimated that, over their 20-year life, these trees will remove more than 4,000 tonnes of CO_2 from the atmosphere.

Shell Canada continues to engage its nearest neighbours to help identify new opportunities to improve its environmental performance. In 2005, the Company began a series of initiatives to enhance the participation of local communities in its monitoring activities. This has led to the development of an education program for Aboriginal youth where they can acquire the technical environmental skills that would enable them to participate fully in community-based monitoring programs.

The AOSP continues to support the communities where it operates, doing business with local and Aboriginal companies in the Regional Municipality of Wood Buffalo and Strathcona County. As well, the AOSP continues to make community investments that enhance and support community health and wellness, education and capacity building.

Oil Sands strives to be best in class operationally and to grow the business.

Looking I

Oil Sands strives to be best in class operationally and to grow the business. Key goals towards delivering these objectives are:

> maintaining production from the existing AOSP operations through continued improvements in reliability;

> reducing AOSP unit operating costs through increased production and improved efficiency;

> advancing AOSP production optimization and debottlenecking activities and expansion opportunities;

> continuing to engage with stakeholders proactively and deliver on commitments made to them; and

> completing additional in situ wells at Peace River to fill the current plant capacity of 12,000 bbls/d while pursuing front-end engineering for the proposed expansion to 30,000 bbls/d.

Capi

Oil Sands planned investment program for 2006 totals $1,120 million compared with $343 million of actual expenditures in 2005. The 2006 program includes $125 million for predevelopment expenses related to future growth projects in Athabasca and Peace River. Proposed investments include $385 million for profitability projects, debottlenecking and production optimization as well as sustaining capital. Capital spending on growth initiatives, including the 100,000 bbls/d AOSP expansion project, will be about $495 million. The 2006 program also provides capital spending of some $115 million at Peace River, mainly for completion of additional wells.

Risk Management

MINE AND UPGRADER RELIABILITY

To minimize the risks associated with plant reliability, Oil Sands will continue to focus on consistently producing at design capacity (155,000 bbls/d) and optimizing facilities to increase production beyond this level. The Company is dedicating resources to develop and maintain operational skills, focusing on technical specialists at the Muskeg River Mine and the Scotford Upgrader to achieve operational improvements. Oil Sands will continue to monitor and improve reliability and efficiency in its operations.

LABOUR AVAILABILITY

With the large number of oil sands projects across Alberta, the ability to attract, develop and retain key technical and project management skills and experienced craft labour to meet Shell's growth objectives presents a major challenge. Furthermore, the level of experience of new staff may lead to reduced labour productivity. Shell's strategy to mitigate these risks is to continue to establish and deliver on recruitment targets for graduate and experienced staff, to implement comprehensive training and development programs, and to work closely with key contractors in support of their employee development activities. Shell's attraction and recruitment program includes, where necessary, international recruitment for skills that are in demand but not readily available in Canada.


Shell
TORE

In 2005, Oil Products annual earnings were $438 million, down slightly from record earnings of $451 million in 2004.

Strong refining margins and improved refinery light oil yields could not fully compensate for lower refinery utilization and higher expenses. The increase in expenses resulted from higher refinery maintenance costs, increased costs for purchased product and higher Long Term Incentive Plan (LTIP) charges. Expenses in 2004 also included a charge relating to a provision for the AIR MILES® reward miles program. Planned maintenance work at the Scotford Refinery and unplanned maintenance at the Montreal East Refinery (MER) resulted in reduced utilization during the second half of the year. High spot prices for purchased products compounded the negative effect of these maintenance activities. Several times during the year, hurricane activity led to supply disruptions and fuel price volatility in North America. However, Shell was able to maintain a reliable supply to customers at competitive prices throughout.

Oil Products earnings in the fourth quarter were $106 million compared with $109 million for the same period in 2004 due to stronger refining and marketing margins. Unfortunately, lower prices for benzene, lower refinery utilization and higher expenses reduced earnings. LTIP charges of $6 million in the fourth quarter of 2005, compared with $30 million in 2004, offset higher maintenance and insurance costs, project-related expenses and commodity price-related costs. A negative tax adjustment of $8 million further reduced fourth-quarter earnings in 2005.

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OIL PRODUCTS EARNINGS
($ millions)

Oil Products earnings just failed to reach the previous year's record high due to product replacement costs and unplanned maintenance.

OIL PRODUCTS EARNINGS ANALYSIS
($ millions)

Earnings in 2005 fell slightly from 2004 due to higher costs and reduced refinery utilization.

OIL PRODUCTS UNIT COSTS
(cents per litre)

In spite of increased expenses, 2005 unit costs remained competitive.

DAVID M. WESTON
Senior Vice President, Oil Products

OIL PRODUCTS HIGHLIGHTS

($ millions except as noted)	**2005**	2004	[illegible]
Revenues	**10 779**	8 535	6 855
Earnings	**438**	451	344
Capital employed	**2 280**	[illegible]	[illegible]
Capital expenditures	**484**	313	194
Return on average capital employed (%)	**19.9**	21.3	17.2

Capital expenditures in 2005 were $484 million compared with $313 million in 2004. A major portion of the total investment was for construction of the ultra-low-sulphur diesel projects at Shell's Montreal East and Scotford refineries. These projects involved construction of new diesel hydrotreater units that will reduce the amount of sulphur in on-road diesel to a maximum of 15 parts per million (ppm) from the present maximum of 500 ppm. This will allow Shell Canada to meet the new federal specifications for ultra-low-sulphur diesel, which come into effect mid-2006.

In 2005, Oil Products remained competitive in terms of unit costs, unit profitability and return on average capital employed (ROACE). Oil Products ROACE was 19.9 per cent compared with 21.3 per cent the previous year.

The continued focus for the business is to deliver quality products and services safely and reliably to customers using value propositions targeted to their specific needs. Equally important is the safe and efficient operation of Shell's three refineries and achieving high, reliable throughput supported by secured sales through branded marketing channels.

Manufacturing and Supply

In 2005, Shell Canada's refineries produced record light oil volumes for the second consecutive year by leveraging the improvements from capital investments in 2004 and 2005. The refineries achieved this record performance in spite of major planned turnarounds at Sarnia Refinery in the spring and at Scotford Refinery in the fall. Unplanned maintenance work at MER in the third and fourth quarters resulted in reduced throughputs and lower light oil yields.

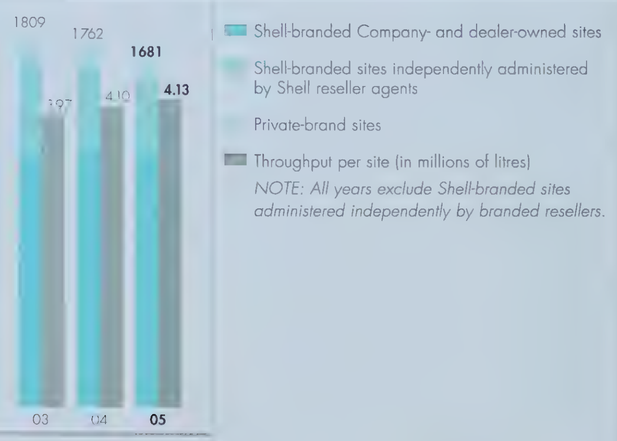
Construction of the ultra-low-sulphur diesel projects at the Montreal East and Scotford refineries continued in 2005. These projects were completed in 2005 and commissioned early in 2006. Feedstock was introduced into both units in February. Work on a third party distillate hydrotreater in Sarnia, which will process distillate from Shell's Sarnia Refinery into ultra-low-sulphur diesel, is underway and completion is expected in the second quarter of 2006. A hydrogen plant is under construction at Shell's Sarnia Refinery, also with completion expected in the second quarter of 2006. The plant will supply hydrogen to the Sarnia Refinery and to the third party facility.

Construction of the new ultra-low-sulphur diesel unit at Shell's Montreal East Refinery was completed in the fourth quarter of 2005.

As a result of a tear in the conveyor belt at the Muskeg River Mine in late February 2006 and the reduction of operations at the mine and the Scotford Upgrader to one train, Scotford Refinery was also running at reduced rates. However, the Company did not anticipate any difficulty in keeping customers supplied.

Retail

The retail gasoline market remained highly competitive and margins were generally compressed throughout 2005. Price volatility in the Greater Toronto and Greater Vancouver areas put even more pressure on margins in these two largest Canadian markets. The high price environment also increased pressure on operating costs, in particular variable and pump-price driven costs such as credit card service fees and loyalty awards. Shell maintained retail market share during the year at an average 17 per cent.



RETAIL SITE PERFORMANCE
(number of sites)

Continuing network rationalization increased throughput in 2005.

In 2005, the Retail business launched a brand awareness advertising campaign to leverage the Shell Group's worldwide expertise in fuels, technology and innovation. Starting in May, national advertising featured an employee of Shell Global Solutions International B.V. explaining how the Shell Group's relationship with Ferrari serves Shell customers and a clean environment. In June, Shell Canada celebrated the launch of V-Power™ gasoline, Shell's unique premium-grade gasoline. The launch was successful, leading to strong premium fuel sales despite declining demand in an environment of rising prices. AIR MILES® reward miles remained a mainstay of the Shell customer value proposition. In spite of the introduction of other loyalty programs into the industry, the AIR MILES® reward miles program continues to build customer loyalty for Shell.

Sheri Snaychuk, Analytical Team Leader at the Calgary Research Centre, is seen here working in the distillation test area, which provides technical support to a number of businesses, including Oil Products.

In 2005, the Retail business also focused on three major initiatives to serve Shell's customers better by improving its processes. First was the Ready for Business program, which was originally introduced in 2004 to create and sustain a culture of operational excellence and help provide a consistently positive customer experience. The second was a new point-of-sale system, which will play a crucial role in improving operational effectiveness to enable Retail to deliver and execute consistently high-quality marketing programs and meet the evolving needs of Shell customers. The third is a new automated fuels-pricing system that will allow the business to respond more effectively to the increasingly competitive and volatile pricing environments, and continue to offer competitive prices. Both new systems are expected to become fully operational in 2006.

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PETROLEUM PRODUCT SALES
(thousands of cubic feet per day)

Further growth in diesel demand increased overall petroleum products sales in 2005.

EARNINGS PER LITRE
(cents per litre)

The decrease in earnings per litre resulted from higher operating costs in 2005

Retail

Key goals for 2005 were improvement in the efficiency of the Company's network of Shell-branded retail sites and increased investment in the major markets, with an emphasis on the Greater Toronto area. The program included building large new-to-industry sites, redeveloping existing sites and closing underperforming sites. During 2005, Shell opened eight new Shell-branded retail sites across the country while completing 11 full-scale redevelopments at existing Shell-branded stations and acquiring three existing retail sites. At year-end, there were 1,681 Shell-branded retail sites compared with 1,762 in 2004. Of the total number, Shell directly operates 760 sites. The average throughput of Shell-operated sites increased to 4.13 million litres in 2005 from 4.10 million litres in 2004.

Commercial

The Commercial business sells branded fuel and lubricants to the aviation, agricultural, industrial, transportation and home-heat sectors, and private-label lubricants to a variety of retailers and commercial distributors. The 2005 business environment was particularly challenging as high crude oil and refined product prices compressed margins in most of these commercial sectors. Shell worked closely with key customers, ensuring minimum inventories were on hand or alternatives available to mitigate the effects of industry-wide supply shortages, which nevertheless affected customers to varying degrees.

ROAD TRANSPORT

In June, Shell Canada Products and Flying J Canada Inc. opened a Flying J facility in Sherwood Park, Alberta, which offers highway hospitality services to long-distance truck drivers, recreational vehicle users and local customers. It is the first Flying J site in Canada to offer Shell-branded gasoline to its customers. Construction will begin soon on a second site in Calgary, Alberta, with a planned opening in late 2006.

Increasingly, customers – especially long-haul trucking customers – consider continental North America to be a single market. The Fleet Processing (FP) Solutions card launched in 2004 was one response to this change. In 2005, the Commercial business introduced the Triton card for retail and local fleet customers. The Triton card includes a web-based tool that allows customers to manage their own card portfolio using the Internet.

Russell Schoeppe, a Shell Territory Manager, visits the first Flying J site in Canada, which sells Shell-branded gasoline to customers.

DISTRIBUTION AND LUBRICANTS SUPPLY

Lubricants blending and packaging volumes at Shell's Brockville plant continued to grow in 2005 and the facility produced record volumes for the fifth consecutive year. Growth came mainly from increases in domestic-branded sales and branded export sales, and private-label product sales that Shell manufactures and packages for third parties.

The Company invests in technology that helps meet customer demands.

In 2005, Shell Canada Products entered an agreement with Royal Dutch Shell's global aviation business to manufacture aviation piston oil and grease at the Brockville and Calgary Lubricants and Grease plants. Work started on a debottlenecking project at the Brockville plant to increase the rail offloading, storage capacity and production blending capabilities. Similar capacity expansion work was completed at the Calgary Lubricants and Grease Plant in 2005.

The U.S. Gulf Coast hurricanes in 2005 severely affected Shell's lubricants supply business, which buys base oils and additives from suppliers in that area. The hurricanes caused the closure of these facilities, resulting in supply shortages. Consequently, Shell had to restrict its sales of a number of lubricant products despite its efforts to minimize the impact of product shortages on its customers.

In 2005, the Oil Products business continued the implementation of quality assurance processes throughout the entire supply chain.

E-BUSINESS

Oil Products is committed to improving the ease and efficiency with which customers can do business with Shell. The Company invests in technology that helps meet customer demands using cost-competitive, automated and standardized processes. To improve service options and reduce costs, Oil Products will continue to automate the administrative processes with its third party alliances, update or replace systems and invest in technology that offers customers self-serve options.

Oil Products reported a combined employee and contractor lost-time injury frequency of 0.19 per 200,000 hours worked compared with 0.13 in 2004. The combined total recordable injury frequency was 1.0 per 200,000 hours worked compared with 1.07 in 2004.

In 2005, the downstream business strengthened its risk and incident management processes.

The MER pioneered a health, safety and environment (HSE) cultural assessment process, which provides the ability to determine the state of HSE awareness and a range of tools to help address areas of weakness.

Oil Products met its 2005 targets for reductions in energy use in manufacturing and is on track to meet longer-term greenhouse gas reduction targets.

In 2005, the Brockville Blending and Packaging Plant, Calgary Lubricants and Grease Plant and Scotford Refinery upgraded their ISO 14001 certifications for sound environmental management in compliance with environmental legislation.

The HSE focus in 2006 will include further improvements in contractor management, enhancement of risk management in downstream operations and continued efforts to improve Oil Products overall safety culture.

Looking Forward

Shell anticipates continuing price volatility in the downstream industry in 2006 as the balance between supply and demand remains tight in the short to medium term, particularly in Eastern Canada. Oil Products' integrated strategy emphasizes:

> targeting safe, reliable and efficient production of high-quality manufactured products at Shell plants, supported by secured, branded sales channels;

> achieving a balance between maximizing short-term profitability and investing for long-term sustainability;

> applying the principles of operational excellence to retain sales volumes through existing marketing channels and pursuing opportunities through carefully chosen alliances;

> delivering capital projects safely, on time and within budget; and

> delivering on the promise of the Shell brand by offering high-quality, differentiated fuels and lubricants.

Capital Investment

The 2006 investment program for Oil Products totals $510 million, up from $484 million of actual expenditures in 2005. The program includes capital to maintain the integrity of the manufacturing and distribution supply infrastructure and marketing networks and to meet the legislated ethanol mandates in Saskatchewan and Ontario. Energy reduction projects in the Sarnia and Montreal East refineries are expected to improve the Company's environmental performance and long-term competitive resilience. The plan also includes capital for the commissioning of ultra-low-sulphur diesel projects at the Scotford and Montreal East refineries, which started up in early 2006 ahead of the mid-year legislative requirement. Shell Canada Products will continue to invest in projects to promote the reliability of supplies in an increasingly demanding environment.

Risk Management

BRAND

A strong brand is the foundation of Shell Canada's profile in the community. Brand value and market share are key assets to be managed. The quality assurance process used to protect the Shell brand and corporate reputation with respect to all fuel products in the market mitigates the risks associated with these intangible assets. Oil Products continues to strengthen its focus on consistency of the retail visual image standard and on the effectiveness of product applications and quality assurance across the entire supply chain.

OPERATIONAL RISK

A key driver of competitive performance in the Oil Products business is the reliability of Shell's refineries. Comprehensive programs, which have been introduced into all these plants, focus on rigorous prioritization and systematic application of engineering and maintenance work to promote safe and reliable operation.

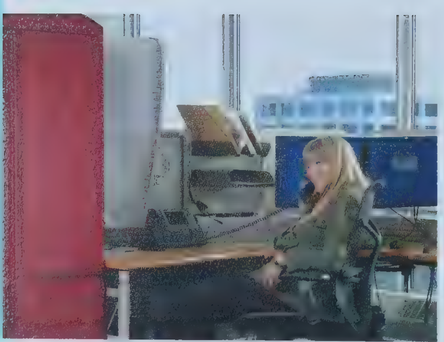
The Corporate departments are responsible for services that support Shell's three main businesses.

These support services include finance; investor relations; information and computing; corporate health, safety, environment and sustainable development; technology (including the Calgary Research Centre); human resources; public affairs; legal services; supply chain management and other corporate services. The activities of these departments are reflected throughout this annual report.

Corporate earnings for 2005 were $121 million compared with earnings of $8 million for 2004. Results benefited from $164 million after-tax due to the use of non-capital losses, offset by a charge of $43 million after-tax related to the Long Term Incentive Plan (LTIP).

In the fourth quarter of 2005, Corporate earnings were $49 million compared with negative earnings of $13 million for the corresponding period in 2004. The increase was mainly due to the use of additional non-capital losses available to the Company following the acquisition of Coral Resources Canada ULC (an affiliated company) in the fourth quarter of 2004. Fourth-quarter 2005 earnings also included an $8 million after-tax charge related to the LTIP compared with $6 million in 2004.

In 2005, Shell Canada's cash flow from operations was a record $3,056 million compared with $2,129 million in 2004. Cash flow from operations was $930 million for the fourth quarter of 2005, up from $437 million for the corresponding period of 2004. In both cases, the increases reflect higher volumes and prices.



Tracy Suskin, who is a member of Shell Canada's office development team, sits at a state-of-the-art workstation in one of the new open-office areas.

The record cash flow allowed the Company to pay off its remaining long-term borrowings and terminate its accounts receivable securitization program. The combined reduction of long-term debt and accounts receivables sales in 2005 amounted to $285 million. Corporate debt at year-end 2005 was limited to $211 million mainly for the mobile equipment lease covering trucks, scrapers and shovels used at the Muskeg River Mine. Strong cash flows also enabled Shell Canada to build up a substantial cash balance of $1,083 million at the end of 2005. With the reduction in debt and buildup of cash balances, the Company was able to reduce bank credit lines required to support the commercial paper program. The board-approved limit for outstanding commercial paper remains at $1.5 billion.

With strong earnings and cash flow during 2005, the Company increased its dividends twice. On July 21, 2005, the Company increased its quarterly dividend to $0.09 per common share from $0.083 (after adjusting for the June 2005 share split). And on November 17, 2005, Shell increased its quarterly dividend a further $0.02 to $0.11 per common share. The full 2005 year-on-year dividend increase was 17 per cent.

Under a normal course issuer bid to offset stock option dilution, which began May 4, 2004, and ended May 3, 2005, Shell Canada repurchased 3,557,241 common shares (adjusted for the share split) at a total cost of $88 million, which includes $34 million of common shares repurchased in 2005.

CATHY L. WILLIAMS
Chief Financial Officer

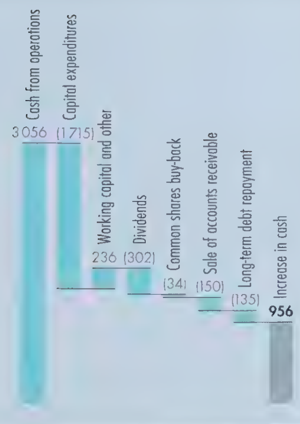
CONTRACTUAL OBLIGATIONS ($ millions)

		Payment Due By Period			
	Total	Less than 1 year	1-3 years	4-5 years	More than 5 years
Long-term debt	210	10	49	151	–
Capital lease obligations	1	1	–	–	–
Operating leases	408	77	117	82	132
Purchase obligations	16 469	1 375	2 185	1 459	11 450
Other long-term obligations	–	–	–	–	–
Total	**17 088**	**1 463**	**2 351**	**1 692**	**11 582**

All of Shell's financing costs in 2005 were based on floating interest rates. Interest and other financing charges were $11 million compared with $26 million in 2004. Elimination of debt financing and accounts receivable sales during the year resulted in lower financing charges.

For most of the year, the Company had positive cash balances resulting in interest income of $9 million compared with $2 million in 2004. Shell Canada typically invests cash balances in short-term money market instruments with counter parties that have a strong credit rating.

On November 17, 2005, Shell announced a $2.7 billion investment program for 2006. The plan includes $2,410 million of capital expenditures and $255 million of related exploration and predevelopment expenses. The Company expects to fund this capital program from the existing cash balance of $1,083 million at the beginning of 2006 and cash from operations. Shell Canada retains a strong corporate credit rating (AA- with Standard & Poor's Rating Services and AA (low) with Dominion Bond Rating Service). The Company also enjoys ready access to short-term debt markets in Canada and can obtain access to longer-term capital markets in both Canada and the United States should the need arise.



CASH FLOW AND FINANCING
($ millions)

Record cash flow in 2005 puts Shell in a strong, virtually debt-free, financial position to finance future growth.

Outstanding Shares

Effective June 21, 2005, the common shares of the Corporation were split on a three-for-one basis for shareholders of record on June 23, 2005.

As at February 28, 2006, the Company had 825,132,812 common shares and 100 preference shares outstanding. There were 23,315,550 employee stock options outstanding at February 28, 2006, of which 12,157,532 are exercisable.

Pension Plan

Shell Canada bases its pension calculation on long-term rates of return. In 2005, Shell Canada's long-term rate of return assumption remained at 7.25 per cent, reflecting the market performance expectation of plan assets. The Company reduced the long-term rate of return assumption for 2006 to 7.0 per cent. In 2005, Shell Canada made current service cost and solvency contributions totalling $80 million to its defined benefit plan.

Accounting Standards

VARIABLE INTEREST ENTITIES

Shell Canada adopted Accounting Guideline 15 *Consolidation of Variable Interest Entities* on January 1, 2005, without prior period restatement.

This standard mandates that the primary beneficiary should consolidate certain entities. Accordingly, the Company consolidated the entity that holds the lease arrangements for large mobile equipment (trucks, scrapers and shovels) used at the Athabasca Oil Sands Project's Muskeg River Mine. The impact of this change resulted in an increase in accounts receivable of $16 million, an increase in properties plant and equipment of $170 million, a decrease in accounts payable of $28 million and an increase in debt of $210 million at December 31, 2005. Adoption of this new standard did not have a material impact on the *Company's Consolidated Statement of Earnings and Retained Earnings.*

LEASE ARRANGEMENTS

Shell Canada adopted EIC-150 *Determining Whether an Arrangement Contains a Lease* effective January 1, 2005. This standard requires companies to analyze arrangements that do not take the legal form of a lease but convey a right to use a tangible asset. An assessment as to whether an arrangement contains a lease is made at the inception of the arrangement. Reassessments are also undertaken when there is a change in the contractual terms, a renewal or extension is exercised, or there are other specified changes. The adoption of this standard had no impact on the Company's financial statements.

EARNINGS PER SHARE

Shell Canada will adopt the amended *Earnings per Share* standard when a final standard is issued. This amendment to the standard proposes to change the guidance for the calculation of diluted earnings per share in the application of the treasury stock method. This amendment is not expected to have a material impact on the computation of diluted earnings per share.

FINANCIAL INSTRUMENTS/HEDGES/COMPREHENSIVE INCOME

Shell Canada will adopt the new financial reporting standards for *Financial Instruments, Hedges and Comprehensive Income* in the first quarter of 2007. These standards are effective for years beginning on or after October 1, 2006. Shell will assess the impact of these standards in 2006.

In the compilation of the financial statements, some estimates reflect management's best judgments. These estimates are based on historical experience and other factors that management deems appropriate. The Audit Committee of the board of directors reviews annually any significant changes in estimates. The following summary outlines the critical accounting estimates made by Shell management and should be read in conjunction with the section "Accounting Policies" on pages 65 to 67 of the Notes to Consolidated Financial Statements.

HYDROCARBON RESERVES

Reserves quantities are estimated in accordance with established guidelines of the Canadian securities regulators, United States Financial Accounting Standards Board and United States Securities Exchange Commission for conventional oil and gas and minable bitumen reserves. Determination of reserves within these guidelines is based on established geological and engineering principles and involves interpretation of geological data. Estimates are subject to revision as additional exploration and development data are collected and new information regarding producing operations and technology becomes available. Revisions could also occur as economic and operating conditions change, or as properties are divested or acquired. Although there is a reasonable certainty of recovering proved reserves, they are based on estimates that are subject to some variability.

ASSET RETIREMENT OBLIGATIONS

Asset retirement obligations and other environmental liabilities are based on commercial engineering estimated costs and historical experience. Calculations take into account the anticipated method and extent of remediation consistent with legal requirements, current technology and the possible use of the location. Since these estimates are specific to the locations involved, there are many individual assumptions underlying the Company's total asset retirement obligations and provision for other environmental liabilities. Significant changes to the assumptions behind these estimates and the timing may result in material changes to the obligation.

Asset retirement obligations are discounted using a credit-adjusted risk-free rate. Payments to settle these obligations occur on an ongoing basis and will continue over the life of the operating assets, which can exceed 25 years. The discount rate on incremental asset retirement obligation estimates will be adjusted as appropriate to reflect long-term changes in market rates and outlook.

EMPLOYEE FUTURE BENEFITS

An independent actuary determines Shell's costs of pension and other retirement benefits using the projected benefit method. The calculation takes into account length of service and estimates of expected plan investment performance, salary increases, expected health care costs and the discount rate for the benefit obligation. Senior management reviews key pension assumptions annually and third party actuaries review them at least every three years. The assumed long-term rate of return used in 2005 was 7.25 per cent compared with an average of actual returns

of 9.6 per cent annually over the last 10 years ended December 31, 2005. Shell's exposure to changes in the underlying assumptions is summarized on page 80 of the *Notes to Consolidated Financial Statements*. The obligation and expense could increase or decrease if there were to be a change in these estimates. Pension expenses represented less than one per cent of Shell's total expenses in 2005.

Related Party Transactions

In the course of regular business activities, Shell Canada enters into transactions with related parties, including affiliates of Royal Dutch Shell plc. The products sold to affiliates include natural gas, petroleum products, chemicals and services. The main product purchased from affiliates is crude oil. All transactions are at commercial rates.

Cecile Siewe, Senior Technology Development Engineer, and Materials Research Advisor Malcolm Hay test materials at Shell's Calgary Research Centre.

Technology

Technology experts provide technical and engineering support to secure the best possible performance from Shell's assets and new business opportunities. Access to Royal Dutch Shell's worldwide research and technical support capabilities augments Shell Canada's capabilities.

Shell regularly assesses asset integrity by reviewing management systems and conducting health, safety and environment and integrity assurance audits of the Company's various facilities.

Risk Management

FINANCIAL RISKS

Currency risk increases when foreign currency rates fluctuate compared with the Canadian dollar. The risk grows in proportion to the volume of activity involving foreign currency. Shell regularly executes commodity transactions priced in other currencies, mainly U.S. dollars. The majority of these U.S. dollar transactions involve crude oil purchases. Netting foreign cash flows across the various businesses each month helps reduce the effect of these fluctuations for the Company overall. During the year, the Company recorded $14 million after-tax in foreign exchange gains. These gains are primarily attributable to working capital holding gains caused by the Canadian dollar appreciation during the year. Shell Canada reviews all foreign currency commitments on major capital projects and, depending on specific circumstances, may hedge on a transaction-by-transaction basis. At year-end 2005, no material hedges were in place.

To reduce the financial risk resulting from potential incidents, the Company purchases appropriate insurance against risks associated with all its operations and projects. Shell's major insurance programs consist of executive protection, property damage and business interruption, third party liability and construction insurance.

FINANCIAL INFORMATION

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MANAGEMENT'S REPORT

TO THE SHAREHOLDERS OF SHELL CANADA LIMITED

The management of Shell Canada Limited is responsible for the preparation of all information included in this Annual Report. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles and necessarily include amounts based on management's informed judgments and estimates. Financial information included elsewhere in this Annual Report is consistent with the consolidated financial statements.

To assist management in fulfilling its responsibilities, a system of internal accounting controls has been established to provide reasonable assurance that the consolidated financial statements are accurate and reliable and that assets are safeguarded. Management believes that this system of internal control has operated effectively for the year ended December 31, 2005.

PricewaterhouseCoopers LLP, Chartered Accountants, appointed by the shareholders, have audited the financial statements and conducted a review of accounting policies and procedures to the extent required by generally accepted auditing standards and performed such tests as they deemed necessary to enable them to express an opinion on the consolidated financial statements.

The Board of Directors, through its Audit Committee, is responsible for ensuring that management fulfills its financial reporting responsibilities. The Audit Committee is composed of independent directors who are not employees of the Corporation. The committee reviews the financial content of the Annual Report and meets regularly with management, internal audit and PricewaterhouseCoopers LLP to discuss internal controls, accounting, auditing and financial reporting matters. The committee recommends the appointment of the external auditors to shareholders. The committee reports its findings to the Board of Directors for its consideration in approving the consolidated financial statements for issuance to the shareholders.

Clive Mather
President and Chief Executive Officer

Cathy L. Williams
Chief Financial Officer

Donna Tarka
Controller

February 21, 2006

AUDITORS' REPORT

TO THE SHAREHOLDERS OF SHELL CANADA LIMITED

We have audited the consolidated balance sheets of Shell Canada Limited as at December 31, 2005, 2004 and 2003 and the consolidated statements of earnings and retained earnings and cash flows for each of the years in the three-year period ended December 31, 2005. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance that the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2005, 2004 and 2003 and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2005, in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta

February 21, 2006

CONSOLIDATED STATEMENT OF EARNINGS AND RETAINED EARNINGS

Year ended December 31 ($ millions)	**2005**	2004	2003
REVENUES			
Sales and other operating revenues	**14 171**	11 197	9 076
Dividends, interest and other income	**223**	91	41
Total revenues	**14 394**	11 288	9 117
EXPENSES			
Cost of goods sold	**7 900**	6 068	5 077
Operating, selling and general	**2 400**	2 048	1 771
Transportation	**331**	309	270
Exploration and predevelopment	**184**	230	88
Depreciation, depletion, amortization and retirements	**782**	722	637
Interest on long-term debt	**8**	16	31
Other interest and financing charges	**3**	10	35
Total expenses	**11 608**	9 403	7 909
EARNINGS			
Earnings before income tax	**2 786**	1 885	1 208
Current income tax	**602**	617	188
Future income tax	**170**	(18)	210
Total income tax (Note 4)	**772**	599	398
Earnings	**2 014**	1 286	810
Per common share (dollars) (Note 13)			
Earnings – basic	**2.44**	1.56	0.98
Earnings – diluted	**2.41**	1.55	0.97
RETAINED EARNINGS			
Balance at beginning of year	**6 011**	5 045	4 529
Earnings	**2 014**	1 286	810
	8 025	6 331	5 339
Common shares buy-back (Note 3)	**33**	61	68
Dividends	**302**	259	226
Balance at end of year	**7 690**	6 011	5 045

CONSOLIDATED STATEMENT OF CASH FLOWS

Year ended December 31 ($ millions)	**2005**	2004	2003
CASH FROM OPERATING ACTIVITIES (Note 1)			
Earnings	**2 014**	1 286	810
Exploration and predevelopment	**99**	160	42
Non-cash items			
Depreciation, depletion, amortization and retirements	**782**	722	637
Future income tax	**170**	(18)	210
Stock-based compensation	**–**	(10)	12
Other items	**(9)**	(11)	(10)
Cash flow from operations	**3 056**	2 129	1 701
Movement in working capital and operating activities			
Accounts receivable securitization program (Note 12)	**(150)**	(431)	61
Other working capital and operating items	**155**	417	(55)
	3 061	2 115	1 707
CASH INVESTED (Note 1)			
Capital, exploration and predevelopment expenditures	**(1 715)**	(951)	(713)
Movement in working capital from investing activities	**69**	(7)	(25)
Capital expenditures and movement in working capital	**(1 646)**	(958)	(738)
Proceeds on disposal of properties, plant and equipment	**6**	4	25
	(1 640)	(954)	(713)
CASH FROM FINANCING ACTIVITIES			
Common shares buy-back (Note 3)	**(34)**	(63)	(71)
Proceeds from exercise of common share stock options	**6**	37	15
Dividends paid	**(302)**	(259)	(226)
Long-term debt and other	**(135)**	(600)	(190)
Short-term financing	**–**	(149)	(522)
	(465)	(1 034)	(994)
Increase in cash	**956**	127	–
Cash at beginning of year	**127**	–	–
Cash at end of year[1]	**1 083**	127	–
Supplemental disclosure of cash flow information			
Dividends received	**15**	14	10
Interest received	**42**	28	18
Interest paid	**12**	28	70
Income tax paid	**683**	303	271

[1] Cash comprises cash and highly liquid short-term investments.

CONSOLIDATED BALANCE SHEET

As at December 31 ($ millions)	**2005**	2004	2003
ASSETS			
Current assets			
Cash and short-term investments	**1 083**	127	–
Accounts receivable	**1 821**	1 213	495
Inventories			
Crude oil, products and merchandise	**535**	501	497
Materials and supplies	**92**	83	83
Prepaid expenses	**71**	85	81
Future income tax (Note 4)	**316**	314	65
	3 918	2 323	1 221
Investments, long-term receivables and other	**671**	549	455
Properties, plant and equipment (Note 2)	**9 066**	8 034	7 937
Total assets	**13 655**	10 906	9 613
LIABILITIES			
Current liabilities			
Short-term borrowings	**–**	–	149
Accounts payable and accrued liabilities and other	**2 242**	1 683	1 157
Income and other taxes payable	**687**	657	255
Current portion of asset retirement and other long-term obligations	**26**	35	17
Current portion of long-term debt (Note 6)	**11**	136	734
	2 966	2 511	2 312
Asset retirement and other long-term obligations (Note 7)	**545**	417	395
Long-term debt (Note 6)	**200**	1	2
Future income tax (Note 4)	**1 730**	1 448	1 366
Total liabilities	**5 441**	4 377	4 075
Commitments and contingencies (Note 11)			
SHAREHOLDERS' EQUITY			
Capital stock (Note 3)			
100 4% preference shares	**1**	1	1
825 102 612 common shares (2004 – 825 727 686; 2003 – 825 126 477)	**523**	517	480
	524	518	481
Contributed surplus	**–**	–	12
Retained earnings	**7 690**	6 011	5 045
Total shareholders' equity	**8 214**	6 529	5 538
Total liabilities and shareholders' equity	**13 655**	10 906	9 613

The consolidated financial statements have been approved by the Board of Directors.

Clive Mather
Director

Kerry L. Hawkins
Director

Shell Canada's consolidated financial statements are prepared in accordance with accounting principles generally accepted in Canada. The Corporation's major accounting policies are summarized as follows:

Note 1. Accounting Policies

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of Shell Canada Limited and its subsidiary companies. The financial statements reflect the Corporation's proportionate interests in joint ventures.

INVENTORIES

The cost of crude oil, products and merchandise are stated at the lower of cost, applied on the last-in, first-out (LIFO) basis, or net realizable value. All other inventories are stated at the lower of cost, applied on a weighted average basis, or net realizable value.

INVESTMENTS

Investments in companies over which Shell Canada exercises significant influence are accounted for using the equity method. Accordingly, the book value of the investment in such companies equals the cost of the investment, plus Shell Canada's share of earnings since the investment date, less dividends received. Other long-term investments are recorded at cost. Short-term investments are carried at the lower of cost or market value and are highly liquid securities with a maturity of three months or less when purchased.

EXPLORATION AND DEVELOPMENT COSTS

The Corporation follows the successful efforts method of accounting for oil and gas exploration and development activities. Under this method, acquisition costs of properties are capitalized. Exploratory drilling costs are initially capitalized and costs relating to wells subsequently determined to be unsuccessful are charged to earnings. Exploratory drilling costs related to exploratory wells in an area that requires major capital expenditures are carried as an asset, provided that i) there have been sufficient oil and gas reserves found to justify completion as a producing well if the required capital expenditure is made, and ii) drilling of additional exploratory wells is underway or firmly planned for the near future. Other exploration costs are charged to earnings. All development costs are capitalized. For mining activities, property acquisition and development costs are capitalized.

DEPRECIATION, DEPLETION AND AMORTIZATION

Depreciation and depletion on oil and gas and mining assets are provided on the unit-of-production basis. Land and lease costs relating to producing properties and costs of gas plants are depleted and depreciated over remaining proved reserves. Oil and gas and mine development costs are depleted and depreciated over remaining proved developed reserves. The mine extraction plant and other facilities are depreciated over remaining proved and probable reserves. Amortization of unproved oil and gas properties is based on the estimated life of the asset and past experience. Costs relating to refinery, upgrader, mine equipment, mine and upgrader preproduction, distribution, marketing and non-resource assets are depreciated on the straight-line basis over each asset's estimated useful life.

ASSET RETIREMENT OBLIGATIONS

Legal obligations associated with site restoration on the retirement of assets with determinable useful lives are recognized when they are incurred, which is typically at the time the assets are installed. The obligations are initially measured at fair value and discounted to present value. A corresponding amount equal to that of the initial obligation is added to the capitalized costs of the related asset. Over time, the discounted asset retirement obligation amount will be accreted for the change in its present value, and the initial capitalized costs will be depreciated over the useful lives of the related assets.

Asset retirement obligations and other environmental liabilities are based on commercial engineering estimated costs and historical experience, taking into account the anticipated method and extent of remediation consistent with legal requirements and current technology.

INTEREST

Interest costs are expensed as incurred.

REVENUES

Revenues are recognized upon delivery. Inter-segment sales, which are accounted for at estimated market-related values, are included in revenues of the segment making the transfer. On consolidation, such inter-segment sales and any associated estimated profits in inventory are eliminated.

ROYALTIES AND MINERAL TAXES

All royalty entitlements and mineral taxes are reflected as reductions in sales and other operating revenues.

EMPLOYEE FUTURE BENEFITS

The costs of the defined benefit pension plan and other retirement benefits are actuarially determined using the projected benefit method prorated on service and management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and expected health care costs. For the purpose of calculating the expected return on plan assets, those assets are valued at a market-related value. The excess of the net actuarial gain or loss over 10 per cent of the greater of the benefit obligation and the market-related value of plan assets is amortized over the expected average remaining service period of active employees. The cost of the Company's portion of the defined contribution pension plan is expensed as incurred.

FOREIGN CURRENCY TRANSLATION

Monetary items are translated to Canadian dollars at rates of exchange in effect at the end of the period. The gains and losses on the translation of foreign denominated monetary items are recognized in earnings.

DERIVATIVE INSTRUMENTS

The Company uses derivative instruments in the management of its foreign currency, interest rate and commodity price exposures. The Company does not use derivative instruments for speculative purposes.

Derivative instruments that do not qualify as hedges, or are not designated as hedges, are recorded using the mark-to-market method of accounting, whereby derivative instruments are recorded on the Company's balance sheet as either an asset or liability with changes in fair value recorded to earnings.

Foreign exchange contracts are used to hedge certain foreign purchases and sales. Those foreign exchange contracts are revalued at the exchange rate in effect at the end of each reporting period. Foreign exchange gains and losses are recognized in earnings.

Interest rate swaps are mark-to-market and used to manage interest rate exposure. Differentials under interest rate swap arrangements are recognized by adjustments to interest expense.

Energy futures are used to reduce exposure to price fluctuations in some contractual energy purchases and sales. Those energy futures are mark-to-market at the end of each reporting period and with the changes recognized in earnings.

VARIABLE INTEREST ENTITIES

The Corporation consolidates entities where it is deemed to be the primary beneficiary. The consolidation of these entities has resulted in the recording of an asset, long-term debt and working capital.

MEASUREMENT UNCERTAINTY

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Significant estimates used in the preparation of these financial statements include the estimate of proved and probable reserves, asset retirement obligations and employee future benefits.

STOCK-BASED COMPENSATION PLANS

The Corporation has stock-based compensation plans, which are described in Note 3. For options under the Long Term Incentive Plan (LTIP) that have share appreciation rights attached to them, a liability for expected cash settlements is accrued over the vesting period of the options based on the difference between the exercise price of the options and the market price of the Company's common shares. The liability is revalued at the end of each reporting period to reflect changes in the market price of the Company's common shares and the net change is recognized in earnings. When options are surrendered for cash, the cash settlement reduces the outstanding liability. When options are exercised for common shares, consideration paid by the option holders and the previously recognized liability associated with the option are recorded as share capital.

For options that do not have share appreciation rights (SARs) attached to them, stock-based compensation is accounted for using the Black-Scholes valuation method. The Company records compensation expense over the vesting period for stock options granted to employees. Any consideration paid by employees on exercise of stock options or purchase of stock is credited to share capital. No compensation expense has been recorded for awards granted prior to 2003.

MINE STRIPPING COSTS

Mine stripping costs are not significant and therefore expensed in the period they are incurred.

CHANGE IN ACCOUNTING POLICY

Variable Interest Entities

Shell Canada adopted Accounting Guideline 15 *Consolidation of Variable Interest Entities* on January 1, 2005, without prior period restatement. This standard mandates that the primary beneficiary should consolidate certain entities. Accordingly, the Company consolidated the entity that holds the lease arrangements for large mobile equipment (trucks, scrapers and shovels) used at the Athabasca Oil Sands Project's Muskeg River Mine.

The impact of this change resulted in an increase in accounts receivable of $16 million, an increase in properties, plant and equipment of $170 million, a decrease in accounts payable of $28 million and an increase in debt of $210 million at December 31, 2005. Adoption of this new standard did not have a material impact on the Company's *Consolidated Statement of Earnings and Retained Earnings.*

RECLASSIFICATION

The *Consolidated Statement of Cash Flows* reflects certain items, primarily exploration expense and pension contributions, as reductions of cash from operating activities. These items were reflected in 2004 as investing activities. The reclassification of these 2004 items reflects exploration costs of $70 million (2003 – $46 million) in earnings from continuing operations, and a pension contribution of $68 million (2003 – $37 million) as a movement in working capital. In addition, the Corporation reclassified certain LTIP expenses of $151 million in 2004 (2003 – nil) as a reduction of cash flow from operations offset by a change in working capital.

Certain other information provided for prior years has been reclassified to conform to the current presentation.

Note 2. Segmented Information

The operating segments are those adopted by senior management of the Corporation to determine resource allocations and assess performance. In all material respects, the segmented information is applied consistently in accordance with the Corporation's significant accounting policies. The Corporation's revenues are attributed principally to Canada where all of its major properties, plants and equipment are located.

Segmented financial results and properties, plant and equipment data are reported as if the segments were separate entities.

EARNINGS ($ millions)

TOTAL			
2005	2004	2003	
1 577	1 306	1 354	Natural gas
842	716	597	Natural gas liquids
1 490	1 024	467	Crude oil and bitumen
(485)	(364)	(354)	Royalties
4 361	3 615	3 074	Gasolines
4 432	3 047	2 374	Middle distillates
1 675	1 600	1 293	Other products
502	344	312	Other revenues
–	–	–	Inter-segment sales
14 394	11 288	9 117	**Total revenues**
7 900	6 068	5 077	Cost of goods sold
–	–	–	Inter-segment purchases
2 400	2 048	1 771	Operating, selling and general
331	309	270	Transportation
184	230	88	Exploration and predevelopment
782	722	637	Depreciation, depletion, amortization and retirements
8	16	31	Interest on long-term debt
3	10	35	Other interest and financing charges
11 608	9 403	7 909	**Total expenses**
2 786	1 885	1 208	Earnings (loss) before income tax
602	617	188	Current income tax
170	(18)	210	Future income tax
772	599	398	Total income tax
2 014	1 286	810	**Earnings (loss)**

The Corporation has the following segments:

Exploration & Production includes exploration, production and marketing activities for natural gas, natural gas liquids, in situ bitumen and sulphur.

Oil Sands includes mining and extraction of bitumen, upgrading of mined bitumen to synthetic crude oils and marketing of these products.

Oil Products includes the manufacturing, distribution and selling of the Corporation's refined petroleum products.

Corporate includes controllership, financing activities, administration and general corporate facility management.

EXPLORATION & PRODUCTION			OIL SANDS			OIL PRODUCTS			CORPORATE		
2005	2004	2003	**2005**	2004	2003	**2005**	2004	2003	**2005**	2004	2003
1 577	1 306	1 354	**–**	–	–	**–**	–	–	**–**	–	–
842	716	597	**–**	–	–	**–**	–	–	**–**	–	–
113	77	81	**1 377**	947	386	**–**	–	–	**–**	–	–
(473)	(355)	(350)	**(12)**	(9)	(4)	**–**	–	–	**–**	–	–
–	–	–	**–**	–	–	**4 361**	3 615	3 074	**–**	–	–
–	–	–	**–**	–	–	**4 432**	3 047	2 374	**–**	–	–
327	329	268	**–**	–	46	**1 348**	1 271	979	**–**	–	–
73	41	28	**140**	32	–	**226**	216	218	**63**	55	66
152	84	135	**1 643**	1 102	478	**412**	386	210	**–**	–	–
2 611	2 198	2 113	**3 148**	2 072	906	**10 779**	8 535	6 855	**63**	55	66
–	–	–	**790**	544	306	**7 108**	5 525	4 767	**2**	(1)	4
225	159	148	**281**	283	146	**1 701**	1 130	529	**–**	–	–
511	422	364	**639**	542	478	**1 133**	1 029	893	**117**	55	36
331	309	270	**–**	–	–	**–**	–	–	**–**	–	–
168	230	88	**16**	–	–	**–**	–	–	**–**	–	–
367	357	282	**209**	171	158	**204**	193	196	**2**	1	1
–	–	–	**–**	–	–	**–**	–	–	**8**	16	31
–	–	–	**–**	–	–	**–**	–	–	**3**	10	35
1 602	1 477	1 152	**1 935**	1 540	1 088	**10 146**	7 877	6 385	**132**	81	107
1 009	721	961	**1 213**	532	(182)	**633**	658	470	**(69)**	(26)	(41)
407	385	382	**45**	16	(253)	**296**	249	95	**(146)**	(33)	(36)
(63)	(113)	(40)	**378**	138	213	**(101)**	(42)	31	**(44)**	(1)	6
344	272	342	**423**	154	(40)	**195**	207	126	**(190)**	(34)	(30)
665	449	619	**790**	378	(142)	**438**	451	344	**121**	8	(11)

CASH FLOW ($ millions)

TOTAL 2005	2004	2003	
3 056	2 129	1 701	Cash flow from operations
5	(14)	6	Movement in working capital and operating activities
3 061	2 115	1 707	**Cash from operating activities**
(1 715)	(951)	(713)	Capital, exploration and predevelopment expenditures
69	(7)	(25)	Movement in working capital from investing activities
(1 646)	(958)	(738)	
6	4	25	Other cash invested
(465)	(1 034)	(994)	Cash from financing activities
956	127	–	**Increase (decrease) in cash**

CAPITAL EMPLOYED ($ millions)

TOTAL 2005	2004	2003	
3 918	2 323	1 221	Current assets
671	549	455	Investments, long-term receivables and other
4 589	2 872	1 676	
15 575	13 843	13 101	Properties, plant and equipment at cost
(6 509)	(5 809)	(5 164)	Accumulated depreciation, depletion and amortization
9 066	8 034	7 937	Net properties, plant and equipment
13 655	10 906	9 613	Total assets
(5 230)	(4 240)	(3 190)	Total liabilities less long-term debt and short-term borrowings
8 425	6 666	6 423	**Capital employed**

EXPLORATION & PRODUCTION			OIL SANDS			OIL PRODUCTS			CORPORATE		
2005	2004	2003	**2005**	2004	2003	**2005**	2004	2003	**2005**	2004	2003
1 056	855	913	**1 388**	686	233	**533**	580	555	**79**	8	–
(86)	159	99	**25**	130	62	**235**	146	(228)	**(169)**	(449)	73
970	1 014	1 012	**1 413**	816	295	**768**	726	327	**(90)**	(441)	73
(873)	(451)	(385)	**(343)**	(179)	(123)	**(484)**	(313)	(194)	**(15)**	(8)	(11)
28	9	(6)	**38**	(26)	(17)	**1**	11	(3)	**2**	(1)	1
(845)	(442)	(391)	**(305)**	(205)	(140)	**(483)**	(302)	(197)	**(13)**	(9)	(10)
1	1	24	**4**	–	–	**1**	2	–	**–**	1	1
–	–	–	**–**	–	–	**–**	–	–	**(465)**	(1 034)	(994)
126	573	645	**1 112**	611	155	**286**	426	130	**(568)**	(1 483)	(930)

EXPLORATION & PRODUCTION			OIL SANDS			OIL PRODUCTS			CORPORATE		
2005	2004	2003	**2005**	2004	2003	**2005**	2004	2003	**2005**	2004	2003
731	542	440	**137**	198	193	**1 742**	1 471	1 163	**1 308**	112	(575)
116	100	87	**89**	69	54	**378**	304	254	**88**	76	60
847	642	527	**226**	267	247	**2 120**	1 775	1 417	**1 396**	188	(515)
5 879	5 097	4 802	**4 366**	3 834	3 667	**5 215**	4 802	4 528	**115**	110	104
(3 236)	(2 886)	(2 544)	**(552)**	(315)	(161)	**(2 650)**	(2 536)	(2 392)	**(71)**	(72)	(67)
2 643	2 211	2 258	**3 814**	3 519	3 506	**2 565**	2 266	2 136	**44**	38	37
3 490	2 853	2 785	**4 040**	3 786	3 753	**4 685**	4 041	3 553	**1 440**	226	(478)
(1 438)	(1 330)	(1 137)	**(1 521)**	(926)	(661)	**(2 405)**	(1 911)	(1 440)	**134**	(73)	48
2 052	1 523	1 648	**2 519**	2 860	3 092	**2 280**	2 130	2 113	**1 574**	153	(430)

Note 3. Capital Stock and Stock-Based Compensation

CAPITAL STOCK

Shell Canada Limited carries on business under the *Canada Business Corporations Act.* Common shares are without nominal or par value and are authorized in unlimited number.

The holder of the four per cent preference shares receives fixed, cumulative dividends of $40,000 per year. The preference shares may be redeemed at the amount paid up thereon plus accrued dividends.

On June 21, 2005, the common shares of the Corporation were split on a three-for-one basis for shareholders of record on June 23, 2005. Common share data and per share information have been restated to reflect the impact of the share split.

On April 30, 2004, Shell Canada Limited announced its intention to make a normal course issuer bid, to repurchase for cancellation up to one per cent of its issued and outstanding common shares as at April 27, 2004. The bid began on May 4, 2004, and expired on May 3, 2005. The bid was used to counter dilution resulting from the issuance of common shares under the Corporation's LTIP. Under this bid, a total of 3,557,241 common shares (adjusted for the share split) were repurchased and cancelled at market prices for a total cost of $88 million, which includes $34 million of shares purchased in 2005.

Under an earlier normal course issuer bid, which commenced February 7, 2003, and ended February 6, 2004, 4,584,000 common shares (adjusted for the share split) were repurchased and cancelled at market prices for a total cost of $80 million, which included $9 million of shares purchased in 2004.

COMMON SHARES		**2005**		2004		2003
	Shares	($ millions)	Shares	($ millions)	Shares	($ millions)
Balance at beginning of year	**825 727 686**	**517**	825 126 477	480	827 724 870	468
Activity during year						
Options exercised	**580 767**	**7**	3 423 909	39	1 514 307	15
Normal course issuer bid	**(1 205 841)**	**(1)**	(2 822 700)	(2)	(4 112 700)	(3)
Balance at year-end	**825 102 612**	**523**	825 727 686	517	825 126 477	480

STOCK-BASED COMPENSATION

Under the LTIP, the Company may grant options to executives, senior management and other employees. The exercise price of each option equals the market price of the Company's stock on the date of grant and the maximum term of an option is 10 years. Options may not be exercised during the one-year period following the date of grant, after which time one-third of the options may be exercised in each of the next three years on a cumulative basis. For executives and senior management, 50 per cent of the options are "performance-based" and their award is tied to the Company's Total Shareholder Return (TSR). For the performance-based options to vest, the Company's three-year TSR must exceed the average of the Corporation's comparator group at the end of the three-year period after being granted. If the Corporation's TSR does not meet the target, the Management Resources and Compensation Committee may determine, in its sole discretion, that all or a portion of the options granted shall vest. If these options vest, they must be exercised within seven years of the date of vesting.

In 2005, the Company granted 5,926,050 (2004 – 5,089,500) options with an exercise price of $26.42 (2004 – $20.85). Of the options granted 2,424,900 (2004 – 843,000) are performance-based options.

In 2004, the Company approved a proposal to attach SARs to existing options as allowed under the LTIP. The majority of option holders accepted this proposal. The LTIP provides the option holders with the right to either purchase common shares at the exercise price or receive cash payments equal to the excess of the market value of the common shares over the exercise price. The modification to existing options under the LTIP was accounted for prospectively and, for the year ended December 31, 2004, the Company recorded compensation expense of $123 million. This amount is net of $29 million of previously recognized compensation expense recorded in prior years as a result of the adoption of the Canadian Institute of Chartered Accountants' amended Section 3870 *Stock-Based Compensation and Other Stock-Based Payments.* Contributed surplus related to unexercised options was transferred to liabilities. The compensation expense recorded in 2005 totalled $173 million.

As at December 31, 2005, the total liability for expected cash settlements with respect to those options attached with SARs under the LTIP was $358 million (2004 – $151 million). During the year ended December 31, 2005, cash payments of $55 million (2004 – $1 million) were made for 2,655,048 (2004 – 100,125) SARs exercised.

At December 31, 2005, the Company had 47,721,018 (2004 – 48,320,985) shares reserved to meet outstanding options for the purchase of common shares.

A summary of the status of the Company's stock option plans as at December 31, 2005, 2004 and 2003, and changes during the years ending on those dates is presented below:

STOCK OPTIONS	2005		2004		2003	
	Options (thousands)	Weighted Average Exercise Price (dollars)	Options (thousands)	Weighted Average Exercise Price (dollars)	Options (thousands)	Weighted Average Exercise Price (dollars)
Outstanding at beginning of year	**18 330**	**15.12**	17 619	12.66	14 331	11.41
Granted	**5 926**	**26.42**	5 090	20.85	5 022	15.34
Exercised – common shares	**(581)**	**9.78**	(3 424)	10.80	(1 515)	9.85
Exercised – SARs	**(2 655)**	**13.13**	(100)	12.82	–	–
Forfeited	**(54)**	**20.70**	(855)	16.31	(219)	11.20
Outstanding at year-end	**20 966**	**18.70**	18 330	15.12	17 619	12.67
Options exercisable at year-end	**9 594**		8 454		8 424	

Stock options outstanding at December 31, 2005:

	Options Outstanding			Options Exercisable	
	Number Outstanding (thousands)	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price (dollars)	Number Exercisable (thousands)	Weighted Average Exercise Price (dollars)
$4 – $11	1 910	2.8	$ 8.02	1 910	$ 8.02
$11 – $17	8 685	6.4	$ 14.69	6 562	$ 14.47
$17 – $23	4 469	8.1	$ 20.85	1 122	$ 20.85
$23 – $29	5 832	9.1	$ 26.38	–	–
$29 – $35	70	9.3	$ 29.81	–	–
	20 966	**7.2**	**$ 18.70**	**9 594**	**$ 13.93**

Note 4. Income Tax

The income tax provision included in the determination of earnings reflects an effective tax rate that is different from the Corporation's statutory tax rate. The following table provides a reconciliation between the effective and statutory rates:

($ millions except as noted)	**2005**	2004	2003
Earnings before income tax	**2 786**	1 885	1 208
Basic corporate tax rate (%)	**37.0**	37.5	38.4
Income tax at basic rate	**1 031**	707	464
Increase (decrease) resulting from:			
Crown royalties and other payments to provinces	**102**	90	107
Resource allowance and other abatement measures	**(107)**	(105)	(82)
Manufacturing and processing credit	**(3)**	(3)	(3)
Changes in income tax rates	**(31)**	(40)	(68)
Capital losses not previously recognized	**–**	(1)	(10)
Tax pools acquired from affiliated company	**(164)**	–	–
Other, including revisions in previous tax estimates	**(56)**	(49)	(10)
Total	**772**	599	398
Effective income tax rates on earnings (%)	**27.7**	31.8	32.9

The Corporation's future income tax asset (liability) is comprised of the following tax-affected temporary differences:

($ millions)	**2005**	2004	2003
Current			
LIFO inventory valuation	**205**	116	67
Non-capital losses carryforward	**–**	149	–
Long Term Incentive Plan	**106**	44	–
Employee future benefits	**2**	(5)	(5)
Asset retirement obligations	**8**	9	3
Other	**(5)**	1	–
Total – current	**316**	314	65
Non-current			
Properties, plant and equipment	**(1 746)**	(1 433)	(1 360)
Employee future benefits	**(110)**	(93)	(74)
Asset retirement obligations	**94**	87	89
Long Term Incentive Plan	**17**	7	–
Other	**15**	(16)	(21)
Total – non-current	**(1 730)**	(1 448)	(1 366)
Net future income tax liability	**(1 414)**	(1 134)	(1 301)

The Corporation has $95 million in capital losses, which may be offset against future capital gains and may be carried forward indefinitely. The future tax benefit of capital losses has not been recognized.

Note 5. Taxes, Royalties and Other

The following amounts were included in the determination of earnings:

($ millions)	**2005**	2004	2003
Items reported separately:			
Income tax	**772**	599	398
Items included in sales or other operating revenues or in operating, selling and general expenses:			
Crown royalties and mineral taxes	**420**	304	289
Royalties paid to private leaseholders	**74**	60	64
Other taxes	**108**	108	84
Research and development expense	**41**	28	10

Note 6. Long-Term Debt

($ millions)	Issued	Maturity	**2005**	2004	2003
Medium-Term Notes					
Floating rate notes[1]	Feb 14, 2002	Dec 15, 2004	**–**	–	237
Floating rate notes[2]	Mar 22, 2002	Mar 15, 2005	**–**	134	140
Floating rate notes[1]	Mar 22, 2002	Jun 15, 2004	**–**	–	105
Floating rate notes[1]	Sep 24, 2002	Sep 24, 2004	**–**	–	250
Capital leases		varying dates	**1**	3	4
Mobile equipment lease		varying dates	**210**	–	–
			211	137	736
Included in current liabilities			**(11)**	(136)	(734)
Total			**200**	1	2

[1] In 2004, floating rate notes totalling $592 million were repaid.

[2] In 2005, floating rate notes totalling $134 million were repaid.

Under the Medium-Term Note Shelf Prospectus filed in December 2001, the Corporation issued five tranches of floating rate notes totalling $745 million in 2002. In 2004, extension options for one tranche initially totalling $140 million were exercised, resulting in $134 million being extended for an additional year. These amounts were repaid in full in 2005. Interest on the floating rate notes was paid quarterly at rates ranging from 10 to 17 basis points above the three-month Canadian Dollar Offer Rate.

Shell Canada adopted Accounting Guideline 15 *Consolidation of Variable Interest Entities* on January 1, 2005, without prior period restatement. Accordingly, the Company consolidated the entity that holds the lease arrangements for large mobile equipment at the Athabasca Oil Sands Project's Muskeg River Mine. The mobile equipment lease has terms ranging from one to five years. Interest fluctuates with prime and was paid monthly at rates ranging from 2.98 per cent to 3.59 per cent.

Repayments of obligations necessary during the next five years are as follows:

$ 11 million in 2006
$ 3 million in 2007
$ 46 million in 2008
$ 103 million in 2009
$ 48 million in 2010.

Note 7. Asset Retirement and Other Long-Term Obligations

($ millions)	2005	2004	2003
Asset retirement obligation	**304**	282	264
Other employee future benefits	**143**	137	128
Other obligations	**122**	33	20
	569	452	412
Included in current liabilities	**(24)**	(35)	(17)
Total	**545**	417	395

The change in the asset retirement obligations is as follows:

($ millions)	2005	2004	2003
Asset retirement obligations liability at January 1	**282**	264	261
Additions	**17**	4	–
Accretion	**15**	14	13
Revisions in estimated cash flows	**15**	20	–
Settlements	**(25)**	(20)	(10)
Asset retirement obligations liability at December 31	**304**	282	264

The total undiscounted amount of the estimated cash flows required to settle the obligations is $540 million (2004 – $475 million), which has been discounted using a credit-adjusted risk-free rate of six per cent. The requirement to settle the obligations can occur during the asset's life but most of the obligations will not be settled until the end of the asset's useful life, which can exceed 25 years in some circumstances.

Note 8. Financial Instruments

($ millions)	Notional Fair Value[1] **2005**	2004	2003	Unrealized Gain (Loss)[2] **2005**	2004	2003
Commodity contracts	**24**	43	37	**1**	–	2
Foreign exchange contracts	**7**	19	29	**–**	–	(2)

($ millions)	Notional Fair Value[1] **2005**	2004	2003	Carrying Value **2005**	2004	2003
Long-term debt[3, 4]	**–**	134	733	**–**	134	732

[1] Notional fair value is the product of the contract volume and the mark-to-market forward price. Purchase and sales positions have not been offset. Amounts disclosed represent the sum of the absolute values of the positions. The reported amounts of financial instruments such as cash equivalents, marketable securities and short-term debt approximate fair value.

[2] Unrealized gain or loss represents the gain or loss the Corporation would incur if the contract was liquidated at December 31.

[3] Long-term debt includes the current portion of debt.

[4] The mobile equipment lease, an entity that was consolidated by the Company in 2005, is not classified as a financial instrument.

The Corporation uses commodity contracts to reduce the risk of price fluctuations of some commodities. Over-the-counter contracts with terms generally no longer than one year are used.

At December 31, commodity contracts outstanding were:

	2005		2004		2003	
($ millions except as noted)	Face Value	Volume[1]	Face Value	Volume[1]	Face Value	Volume[1]
Crude oil and refined products commitments	**22**	**296**	43	810	35	943
Electricity commitments	**1**	**9**	–	–	–	3

[1] Crude oil and refined products volumes are expressed as thousands of barrels and electricity is denoted in thousands of megawatt hours.

A portion of the Corporation's cash flow is in U.S. dollars. The U.S. dollar receipts are less than U.S. dollar disbursements primarily due to the cost of foreign crude cargoes exceeding U.S. dollar denominated product sales. The resulting net shortage of U.S. dollars is funded through U.S. dollar spot, forward and swap contracts. These instruments generally mature in less than 30 days. U.S. dollar requirements for significant capital projects and some marketing transactions are funded through forward contracts with maturities generally of less than one year.

Non-performance by the other parties to the financial instruments exposes the Corporation to credit loss. The counterparties for most of the commodity contracts are affiliates of Royal Dutch Shell plc. Other financial instrument contracts are generally with domestic and international banks or corporations, all with credit ratings of A or better. There is no significant concentration of credit risk and Shell does not anticipate non-performance by the counterparties.

Note 9. Employee Future Benefits

Employees initially participate in the defined contribution segment of the Corporation's pension plan. After meeting certain service and age requirements, employees can elect to participate in the defined benefit segment of the pension plan. Benefits from these segments are either partially or fully paid by the Company and are based on years of service and final average earnings. Benefits from the defined benefit segment of the pension plan are indexed for inflation after retirement. In addition to the pension plan, life insurance and supplementary health and dental coverage benefits are provided to retirees. The effective date of the most recent actuarial valuation for funding purposes was December 31, 2005. The next actuarial valuation for funding purposes must be no later than December 31, 2008.

ACCRUED BENEFIT OBLIGATION ($ millions)	**2005**		2004		2003	
	Pension Benefits	Other Benefits	Pension Benefits	Other Benefits	Pension Benefits	Other Benefits
Accrued benefit obligation as at January 1	**2 204**	**168**	1 998	182	1 809	163
Current service cost	**38**	**1**	32	1	28	1
Interest cost	**126**	**10**	118	11	117	10
Actuarial loss (gain)	**41**	**9**	25	(13)	10	3
Transfers	**28**	**–**	25	–	19	–
Benefits paid	**(134)**	**(7)**	(129)	(7)	(126)	(7)
Change in assumption	**265**	**39**	135	(9)	141	18
Plan amendments	**–**	**–**	–	3	–	(6)
Accrued benefit obligation as at December 31	**2 568**	**220**	2 204	168	1 998	182

Included in the above pension benefits are unfunded amounts for the supplemental pension obligations of $177 million (2004 – $143 million; 2003 – $111 million) and $29 million (2004 – $29 million; 2003 – $30 million) for the spousal pension obligations.

PLAN ASSETS ($ millions)	**2005**		2004		2003	
Plan assets as at January 1	**1 976**	**–**	1 782	–	1 648	–
Actual return on plan assets	**232**	**–**	182	–	194	–
Employer contributions	**89**	**7**	119	7	51	7
Employee contributions	**3**	**–**	3	–	2	–
Transfers	**28**	**–**	25	–	19	–
Benefits paid	**(134)**	**(7)**	(129)	(7)	(126)	(7)
Expenses	**(6)**	**–**	(6)	–	(6)	–
Fair value as at December 31	**2 188**	**–**	1 976	–	1 782	–
Funded status – deficit	**(380)**	**(220)**	(228)	(168)	(216)	(182)
Unamortized net losses[1]	**952**	**60**	805	12	761	36
Unamortized past service cost	**–**	**3**	–	3	–	–
Unamortized transitional (asset) obligation[2]	**(108)**	**14**	(143)	16	(179)	18
Accrued benefit asset (obligation)[3]	**464**	**(143)**	434	(137)	366	(128)

[1] Unamortized net losses are amortized over the expected average remaining service period of active employees, which is currently nine years (2004 – nine years; 2003 – eight years).

[2] Three years remain in the amortization of the pension benefit transitional asset. Six years remain in the amortization of the other benefit transitional obligation.

[3] The accrued benefit asset (obligation) is included in the "Investments, long-term receivables and other" line on the Consolidated Balance Sheet.

The percentage of the fair value of total plan assets held at December 31 is as follows:

(per cent)	**2005**	2004	2003
Equity securities	**49.4**	46.9	44.4
Debt securities	**43.8**	40.3	45.8
Real Estate	**3.5**	3.4	3.2
Other	**3.3**	9.4	6.6
Total	**100**	100	100

EXPENSE ($ millions)	**2005**		2004		2003	
	Pension Benefits	Other Benefits	Pension Benefits	Other Benefits	Pension Benefits	Other Benefits
Current service cost	**38**	**1**	32	1	28	1
Employee contributions	**(3)**	**–**	(3)	–	(2)	–
Interest cost	**126**	**10**	118	11	117	10
Plan amendments	**–**	**–**	–	3	–	(6)
Actual return on plan assets	**(232)**	**–**	(182)	–	(194)	–
Actuarial loss (gain) on accrued benefit obligation	**306**	**48**	160	(22)	151	21
Costs arising in the period	**235**	**59**	125	(7)	100	26
Differences between costs arising in the period and costs recognized in the period in respect of:						
Return on plan assets	**95**	**–**	53	–	63	–
Actuarial loss (gain)	**(235)**	**(47)**	(91)	24	(108)	(21)
Plan amendments	**–**	**–**	–	(3)	–	6
Transitional obligation (asset)	**(36)**	**2**	(36)	2	(36)	3
Net expense for benefit plan	**59**	**14**	51	16	19	14
Defined contribution segment	**21**	**–**	13	–	12	–
Total	**80**	**14**	64	16	31	14

ASSUMPTIONS (per cent)	**2005**		2004		2003	
Discount rate	**5.00**	**5.00**	5.80	5.80	6.00	6.00
Long-term rate of return on plan assets[1]	**7.25**	**–**	7.25	–	7.50	–
Rate of compensation growth	**4.70**	**4.70**	4.70	4.70	3.20	3.20
Health-care trend rate[2]	**–**	**7.01**	–	5.92		6.12

[1] The long-term rate of return on plan assets was used in the pension calculation for the fiscal year noted. For 2006, the long-term rate of return on plan assets has been reduced to 7.0 per cent.

[2] The health-care trend rate is a weighted average of medical, dental, and provincial health-care trend rates, decreasing each year to a rate of 4.0 per cent in 2014 and thereafter.

ASSUMPTIONS SENSITIVITIES ($ millions)	One Per Cent Increase	One Per Cent Decrease
Discount rate		
Effect on pension benefit expense	(28)	35
Effect on accrued benefit obligation	(320)	404
Long-term rate of return on plan assets		
Effect on pension benefit expense	(21)	21
Rate of compensation growth		
Effect on pension benefit expense	11	(9)
Effect on accrued benefit obligation	62	(56)
Health-care cost trend rate		
Effect on current service and interest cost	1	(1)
Effect on accrued benefit obligation	24	(19)

Note 10. Transactions with Affiliated Companies

In the course of its regular business activities, Shell Canada enters into routine transactions with affiliates of the Company's majority shareholder. Such transactions are at commercial rates. The amounts paid or received on transactions with Shell International Trading Company and other affiliates of Royal Dutch Shell plc that are reflected in the *Consolidated Statement of Earnings and Retained Earnings* are shown in the table below:

($ millions)	**2005**	2004	2003
Purchases of crude oil, petroleum products, chemicals and service agreements	**5 507**	3 961	2 707
Amounts payable in respect of such purchases	**204**	393	228
Sales of natural gas, petroleum products and chemicals	**2 343**	1 928	1 609
Amounts receivable in respect of such sales	**245**	215	138

Royal Dutch Shell plc provides support and technology for operating locations to Shell Canada. Through these service agreements, Shell Canada has access and rights to research and development and technical expertise.

In December 2004, the Corporation purchased the shares of a related party, Coral Resources Canada ULC, for $39 million. The purchase price was established by negotiation with consideration of comparable commercial transactions. As a result of this transaction, Shell Canada acquired non-capital losses to be used against future taxable income. The losses were fully recognized in 2005.

Note 11. Commitments and Contingencies

At December 31, 2005, the Corporation had non-cancellable operating and other long-term commitments with an initial or remaining term of one year or more. Future minimum payments under such commitments are estimated to be:

($ millions)	Operating Commitments[1]	Other Long-Term Commitments[2]
2006	77	1 375
2007	64	1 309
2008	53	876
2009	44	762
2010	38	697
thereafter	132	11 450[3]

[1] These operating commitments cover leases of service stations, office space and other facilities.

[2] The Corporation has substantial commitments for use of facilities or services and supply and processing of products all made in the normal course of business.

[3] The Corporation has a commitment of $9.5 billion to purchase certain feedstocks from the other joint venture participants in the Athabasca Oil Sands Project (AOSP). This commitment is for the period up to 2028, and is based on the current year pricing premise. Various pipeline charges of $1.0 billion and $0.9 billion of AOSP utilities and hydrogen commitments are also included in the total.

Various lawsuits are pending against the Corporation. Actual liability with respect to these lawsuits is not determinable, but management believes, based on counsels' opinions, that any potential liability will not materially affect the Corporation's financial position.

Note 12. Sale of Accounts Receivable

In 2005, the previously approved accounts receivable securitization program of $600 million was reduced to zero (2004 – $150 million) and the Corporation elected to terminate the program.

Note 13. Earnings Per Share

	2005	2004	2003
Earnings ($ millions)	**2 014**	1 286	810
Weighted average number of common shares (millions)	**825**	826	826
Dilutive securities (millions)			
Options on Long Term Incentive Plan [1]	**9**	6	5
Basic earnings per share (dollars) [2]	**2.44**	1.56	0.98
Diluted earnings per share (dollars) [3]	**2.41**	1.55	0.97

[1] The amount shown is the net number of common shares outstanding after the notional exercise of the share options and the cancellation of the notionally repurchased common shares as per the treasury stock method.

[2] Basic earnings per share is the earnings divided by the weighted average number of common shares.

[3] Diluted earnings per share is the earnings divided by the aggregate of the weighted average number of common shares plus the dilutive securities.

On June 21, 2005, the common shares of the Corporation were split on a three-for-one basis for shareholders of record on June 23, 2005. Common share data and per share information have been restated to reflect the impact of the share split.

SUPPLEMENTAL OIL PRODUCTS DISCLOSURE

Year ended December 31 (unaudited)

PRODUCTION (thousands of cubic metres/day)	**2005**	2004	2003
Crude oil processed by Shell refineries			
Montreal East (Quebec)	**18.6**	17.6	18.2
Sarnia (Ontario)	**10.4**	10.9	10.1
Scotford (Alberta)[1]	**15.9**	16.6	14.6
Total	**44.9**	45.1	42.9
Rated refinery capacity at year-end			
Montreal East (Quebec)	**20.7**	20.7	19.4
Sarnia (Ontario)	**12.0**	12.0	11.4
Scotford (Alberta)	**18.9**	17.7	18.2
Total	**51.6**	50.4	49.0

SALES (thousands of cubic metres/day)	**2005**	2004	2003
Gasolines	**21.0**	20.9	20.9
Middle distillates	**21.0**	19.2	17.9
Other products	**7.1**	7.4	6.9
Total	**49.1**	47.5	45.7

	2005	2004	2003
Refinery utilization (per cent)[2]	**87**	89	90
Earnings per litre (cents)[3]	**2.4**	2.6	2.1

[1] Crude oil processed by Shell refineries includes upgrader feedstock supplied to Scotford Refinery.

[2] Refinery utilization equals crude oil processed by Shell refineries divided by total capacity of Shell refineries, including capacity uplifts at Scotford Refinery due to processing of various streams from the upgrader.

[3] Oil Products earnings per litre equals Oil Products earnings after-tax divided by total Oil Products sales volumes.

SUPPLEMENTAL EXPLORATION & PRODUCTION DISCLOSURE

Year ended December 31 (unaudited)

PRODUCTION[1]	2005	2004	2003
Natural gas (millions of cubic feet/day)			
Gross	**512**	540	562
Net	**413**	449	467
Ethane, propane and butane (thousands of barrels/day)			
Gross	**23.3**	25.1	26.7
Net	**18.6**	19.9	21.3
Condensate (thousands of barrels/day)			
Gross	**15.3**	15.2	16.8
Net	**11.8**	11.8	13.1
Bitumen (thousands of barrels/day)			
Gross	**8.9**	8.1	9.2
Net	**8.7**	7.9	9.1
Sulphur (thousands of long tons/day)			
Gross	**5.3**	5.6	5.9
Net	**4.8**	4.9	5.1

[1] Gross production includes all production attributable to Shell's interest before deduction of royalties; net production is determined by deducting royalties from gross production.

SALES[2]	2005	2004	2003
Natural gas – gross (millions of cubic feet/day)	**510**	536	555
Ethane, propane and butane – gross (thousands of barrels/day)	**38.2**	44.0	44.5
Condensate – gross (thousands of barrels/day)	**20.7**	19.6	17.9
Bitumen products – gross (thousands of barrels/day)	**11.8**	11.5	13.9
Sulphur – gross (thousands of long tons/day)	**11.7**	11.3	10.7

[2] Sales volumes include own production, inventory and brokered third party sales.

PRICES	2005	2004	2003
Natural gas average plant gate netback price ($/mcf)	**8.23**	6.49	6.46
Ethane, propane and butane average field gate price ($/bbl)	**34.79**	28.71	25.48
Condensate average field gate price ($/bbl)	**66.76**	50.46	41.13

EXPLORATION AND DEVELOPMENT WELLS DRILLED

	2005		2004		2003	
	Gross	Net	Gross	Net	Gross	Net
Exploration						
Gas	**4**	**2**	3	1	3	1
Dry	**5**	**3**	4	2	5	4
	9	**5**	7	3	8	5
Development						
Gas	**12**	**8**	10	8	7	4
Bitumen	**9**	**9**	–	–	–	–
Dry	**–**	**–**	1	–	1	1
	21	**17**	11	8	8	5
Total wells drilled	**30**	**22**	18	11	16	10
Wells in progress	**52**	**49**	19	15	10	7

Exploration wells – Wells drilled either in search of new and as yet undiscovered pools of oil or gas, or with the expectation of significantly extending the limits of established pools. All other wells are development wells.

PRODUCTIVE WELLS

	2005		2004		2003	
	Gross	Net	Gross	Net	Gross	Net
Gas wells						
Alberta	**321**	**271**	303	259	294	252
British Columbia	**2**	**1**	1	1	1	1
Nova Scotia	**18**	**6**	15	5	15	5
	341	**278**	319	265	310	258
Bitumen wells						
Alberta	**65**	**65**	58	58	58	58
Total productive wells	**406**	**343**	377	323	368	316

Productive wells – Producing and non-unitized wells capable of producing.

Gross wells – The number of wells in which Shell Canada has a working interest.

Net wells – The aggregate of the numbers obtained by multiplying each gross well by the percentage working interest of Shell Canada therein, rounded to the nearest whole number.

RESERVES

The Corporation's reserves disclosure and related information have been prepared in reliance on a decision of the applicable Canadian securities regulatory authorities under *National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities* (NI 51-101), which permits the Corporation to present its reserves disclosure and related information in accordance with the applicable requirements of the United States Financial Accounting Standards Board (FASB) and the United States Securities and Exchange Commission (SEC). This disclosure differs from the corresponding information required by NI 51-101. If Shell Canada had not received the decision, it would be required to disclose proved plus probable oil and gas reserves estimates based on forecast prices and costs and information relating to future net revenue using forecast prices and costs.

Reserves estimates are prepared by the Corporation's internal qualified reserves evaluators. No independent qualified reserves evaluator or auditor was involved in the preparation of the Corporation's reserves data. An external, independent petroleum consulting firm audited 100 per cent of the proved oil and gas reserves estimates prepared by the Corporation's internal reserves evaluators and verified compliance with applicable FASB and SEC requirements.

RESERVES QUANTITY INFORMATION

Estimation of reserves quantities is based on established geological and engineering principles and involves judgmental interpretation of reservoir data. These estimates are subject to revision as additional information from drilling, seismic, production performance and technology becomes available, as economic and operating conditions change, or as properties are divested or acquired. The difference between the gross and net reserves is the volume dedicated to meet royalty payments over the life of the reserves. The net reserves in the table below have been calculated on the basis of royalty rates and economic conditions in place as at year-end. Shell Canada's estimated proved reserves exclude quantities in the Mackenzie Delta and Arctic Islands, or that otherwise may have been discovered but not yet proved.

OIL, GAS AND OTHER RESERVES

	NATURAL GAS (billions of cubic feet)		
	2005	2004	2003
Net proved developed and undeveloped reserves			
Beginning of year	**1 239**	1 365	1 806
Revisions of previous estimates	**(44)**	(51)	(335)
Extensions, discoveries and other additions	**135**	122	34
Improved recovery methods	**–**	4	30
Purchases of reserves in place	**6**	–	–
Sales of reserves in place	**–**	(37)	–
Production	**(151)**	(164)	(170)
End of year	**1 185**	1 239	1 365
Net proved developed reserves			
End of year	**752**	893	1 082
Gross proved developed and undeveloped reserves			
End of year	**1 592**	1 595	1 775
Gross proved developed reserves			
End of year	**1 026**	1 160	1 415

Proved reserves – Estimated quantities of natural gas, natural gas liquids, bitumen and sulphur that geological engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs. These estimates are based on existing economic and operating conditions (prices, costs, royalties and income taxes) as at year-end.

Proved developed reserves – Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

NATURAL GAS

In 2005, total net natural gas proved reserves decreased by 54 billion cubic feet (bcf) to 1,185 bcf from 1,239 bcf in 2004. Additions of 135 bcf due to extensions and discoveries included an additional booking of 54 bcf for Tay River attributed to a planned development well and 38 bcf for the basin-centered gas area wells. The balance of these additions resulted from continued exploration success in northeast British Columbia and development drilling in the Foothills. The acquisition of interest in three gas wells in the Burmis region of southern Alberta added six bcf. These additions were offset by a reduction of 44 bcf reflecting economic conditions and new technical information, mainly due to higher natural gas royalty payments over the life of the reserves. Production of 151 bcf further reduced reserves.

NATURAL GAS LIQUIDS

Production of 11 million barrels was partially offset by positive technical and economic revisions of three million barrels resulting in a year-end 2005 net proved reserves position of 54 million barrels.

BITUMEN

In 2005, 28 million net proved barrels of Peace River bitumen reserves were rebooked. In 2004, adherence to United States SEC reserves reporting rules and related guidance prescribing the use of constant year-end pricing and costs for proved reserves determination resulted in the Company debooking all proved Peace River bitumen reserves.

Over 2005, Shell Canada developed a new strategy for development of the Peace River lease, which includes plans for a proposed expansion project. The 28 million barrels rebooked for 2005 is solely the reserves portion attributable to the existing and currently drilling wells, and existing facilities. Progression of the engineering and regulatory work for the expansion will continue over the next two years before reaching a final investment decision.

SULPHUR

Net sulphur reserves remained unchanged during 2005 due to reserves additions principally at Tay River, offset by current year production.

NATURAL GAS LIQUIDS (millions of barrels)			BITUMEN (millions of barrels)			SULPHUR (millions of long tons)		
2005	2004	2003	**2005**	2004	2003	**2005**	2004	2003
62	77	105	**–**	167	183	**14**	13	14
3	(4)	(17)	**31**	(164)	(13)	**–**	1	1
–	1	1	**–**	–	–	**2**	2	–
–	–	1	**–**	–	–	**–**	–	–
–	–	–	**–**	–	–	**–**	–	–
–	–	–	**–**	–	–	**–**	–	
(11)	(12)	(13)	**(3)**	(3)	(3)	**(2)**	(2)	(2)
54	62	77	**28**	–	167	**14**	14	13
44	54	69	**11**	–	27	**10**	10	12
71	78	95	**28**	–	182	**14**	14	15
57	68	85	**11**	–	27	**10**	11	14

Proved undeveloped reserves – Reserves that are expected to be recovered from new wells on undrilled acreage adjacent to producing acreage, or from existing wells where further significant expenditure is required.

Gross proved reserves – Reserves estimates before the deduction of royalty interests owned by others.

Net proved reserves – Reserves estimates after deduction of royalties and, therefore, only those quantities that Shell has a right to retain.

SUPPLEMENTAL OIL SANDS DISCLOSURE

Year ended December 31 (unaudited)

PRODUCTION[1] (thousands of barrels/day)	**2005**	2004	2003
Bitumen			
Gross	**95.9**	81.3	46.3
Net	**95.0**	80.5	45.8

Gross production includes all production attributable to Shell's interest before deduction of royalties; net production is determined by deducting royalties from gross production

SALES[2] (thousands of barrels/day)	**2005**	2004	2003
Synthetic crude sales excluding blend stocks	**99.4**	83.7	46.1
Purchased upgrader blend stocks	**37.1**	38.2	17.7
Total synthetic crude sales	**136.5**	121.9	63.8

[2] Sales volumes include third party and inter-segment sales.

UNIT COSTS[3] ($/bbl)	**2005**	2004	2003
Cash operating cost – excluding natural gas	**17.08**	17.79	–
Cash operating cost – natural gas	**6.08**	5.53	–
Total cash operating cost	**23.16**	23.32	–
Depreciation, depletion and amortization	**5.77**	5.59	–
Total unit cost	**28.93**	28.91	–

[3] Total unit cost, including unit cash operating and unit depreciation, depletion and amortization (DD&A) costs, does not have any standardized meaning prescribed by Canadian generally accepted accounting principles (GAAP) and therefore may not be comparable with the calculation of similar measures for other companies.

Unit cash operating cost for Oil Sands is defined as: operating, selling and general expenses plus cash cost items included in cost of goods sold (COGS), divided by synthetic crude oil sales excluding blend stocks. Cash cost items included in COGS in 2005 were $201 million.

Unit DD&A cost for Oil Sands is defined as: DD&A cost divided by synthetic crude oil sales excluding blend stocks. Unit DD&A cost includes preproduction costs, which were written off over the first three years of the project life (2003-2005) and account for $1.59 per barrel of the total unit DD&A cost in 2005.

PRICES ($/bbl)	**2005**	2004	2003
Synthetic crude average plant gate price	**57.55**	44.67	34.18

RESERVES

The Muskeg River Mine development on Lease 13 was designed to access proved and probable reserves of bitumen totalling 1.7 billion barrels (total project) over 30 years of operation starting in 2003 at the average design production level of 155,000 barrels per day. The reserves base includes reserves from the areas to the west of the Muskeg River where mining operations began, as well as reserves located immediately to the east of the Muskeg River.

The reserves estimates are based upon a detailed geological assessment including drilling and laboratory tests. They also consider current mine plans, planned operating life and regulatory constraints. The current proved plus probable reserves estimates include only the portion of Lease 13 that represents the development area approved by the Alberta Energy and Utilities Board. The reserves estimates are based on the actual barrels of bitumen to be shipped for processing at the Scotford Upgrader. No allowance for volume losses during upgrading is required because of the Scotford Upgrader's hydroconversion upgrading process.

Drilling density is a factor in classifying reserves as either proved or probable. Proved reserves of bitumen are based on drill hole spacing of less than 350 metres. Probable reserves of bitumen are based on drill hole spacing of less than 700 metres. Classification of both proved and probable reserves of bitumen possesses a high degree of geological certainty and is predicated on the application of commercial mining, bitumen extraction and froth cleanup technology. For 2005, a technical revision was made to classify proved reserves using a 12.25-hectare area of influence derived from the 350-metre drill hole spacing and, during the year, an additional 268 core holes were drilled. This has resulted in the reclassification of 222 million barrels of gross reserves to proved from probable.

Production accounted for the only change made to the total proved and probable reserves in 2005. Shell's 60 per cent interest in the total reserves amounts to 808 million barrels of proved and 128 million barrels of probable reserves. This estimate is before deduction of royalty barrels. Under the *Oil Sands Royalty Regulation 1997*, royalties depend on project cash flows. Therefore, the calculation of royalties depends on price, production rates, capital costs and operating costs over the life of the Muskeg River Mine and future expansion projects. Using 2005 year-end pricing, Shell's net reserves would be 746 million barrels of proved and 119 million barrels of probable reserves.

The Corporation's minable bitumen reserves disclosure and related information have been prepared in reliance on a decision of the applicable Canadian securities regulatory authorities under *National Instrument NI 51-101 – Standards of Disclosure for Oil and Gas Activities* (NI 51-101), which permits the Corporation to present its reserves disclosure and related information in accordance with the applicable requirements of the FASB and the SEC. If Shell had not received the decision, it would be required to disclose minable bitumen reserves estimates based on forecast prices and costs and information relating to future net revenue using constant and forecast prices and costs.

Reserves estimates are prepared by the Corporation's internal qualified reserves evaluators. No independent qualified reserves evaluator or auditor was involved in the preparation of the Corporation's reserves data.

OIL SANDS RESERVES	MINABLE BITUMEN (millions of barrels)		
	2005	2004	2003
Gross proved reserves			
Beginning of year	**621**	651	600
Revisions of previous estimates	**222**	–	–
Additions	**–**	–	68
Production	**(35)**	(30)	(17)
End of year	**808**	621	651
Gross probable reserves			
Beginning of year	**350**	350	300
Revisions of previous estimates	**(222)**	–	–
Additions	**–**	–	50
End of year	**128**	350	350
Gross proved and probable reserves	**936**	971	1 001
Net proved reserves	**746**	615	572
Net probable reserves	**119**	347	307
Net proved and probable reserves	**865**	962	879

Proved reserves – the quantity of proved reserves is computed from dimensions revealed in outcrops, trenches, workings or drill holes. Grade and/or quality are computed from the results of detailed sampling. The sites for inspection, sampling and measurement are spaced so closely and the geological character is so well defined that size, shape, depth and mineral content of the reserves are well established.

Probable reserves – the quantity and grade and/or quality of probable reserves are computed from information similar to that used for proved reserves. However, the sites for inspection, sampling and measurement are farther apart or are otherwise less adequately spaced. Although the degree of assurance is less than that for proved reserves, it is sufficient to assume continuity between points of observation.

SUPPLEMENTAL LANDHOLDINGS DISCLOSURE

As at December 31 (unaudited)

	UNDEVELOPED				DEVELOPED			
	2005		2004		2005		2004	
(thousands of acres)	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Onshore within the provinces								
Conventional oil and gas:								
Alberta	**294**	**151**	331	173	**551**	**388**	552	384
British Columbia	**316**	**221**	286	220	**–**	**–**	–	–
Quebec	**5**	**–**	5	–	**–**	**–**	–	–
Coal bed methane:								
Alberta	**24**	**24**	24	24	**–**	**–**	–	–
British Columbia	**1 043**	**1 043**	1 018	1 018	**–**	**–**	–	–
Basin-centred gas								
Alberta	**118**	**114**	42	38	**–**	**–**	–	–
British Columbia	**70**	**70**	–	–	**–**	**–**	–	–
Bitumen:								
– mining [1]	**199**	**189**	120	105	**11**	**7**	11	7
– in situ	**87**	**87**	85	85	**18**	**18**	7	7
	2 156	**1 899**	1 911	1 663	**580**	**413**	570	398
Canada Lands								
Offshore Nova Scotia	**517**	**198**	840	322	**109**	**34**	109	34
Orphan Basin	**5 249**	**1 050**	–	–	**–**	**–**	–	–
Northwest Territories	**65**	**55**	262	245	**–**	**–**	–	–
Offshore West coast	**13 590**	**12 845**	13 590	12 845	**–**	**–**	–	–
Nunavut Territory	**5 801**	**3 100**	5 801	3 100	**–**	**–**	–	–
Beaver River	**1**	**–**	–	–	**–**	**–**	–	–
	25 223	**17 248**	20 493	16 512	**109**	**34**	109	34
Total	**27 379**	**19 147**	22 404	18 175	**689**	**447**	679	432

[1] Mining net undeveloped landholdings includes options by other parties not yet exercised.

Gross acres include the interests of others; net acres exclude the interests of others.

Developed lands are leases and other forms of title documents issued by owners or legislative authorities that contain a well, or are in close proximity to other lands that contain a well that has been drilled or completed to a point that would permit production of commercial quantities of oil and gas.

Undeveloped lands are all lands that are not developed and that retain exploration rights.

SUPPLEMENTARY FINANCIAL DATA AND QUARTERLY STOCK-TRADING INFORMATION

Year ended December 31 (unaudited)

DATA PER COMMON SHARE (dollars except as noted)	**2005**	2004	2003
Earnings – basic	**2.44**	1.56	0.98
Earnings – diluted	**2.41**	1.55	0.97
Dividends	**0.367**	0.313	0.273
Common shareholders' equity	**9.96**	7.90	6.70
Common shares outstanding at year-end (millions)	**825**	826	826
Registered shareholders (number at year-end)	**2 361**	2 454	2 554

On June 21, 2005, the common shares of the Corporation were split on a three-for-one basis for shareholders of record on June 23, 2005. Common share data and per share information have been restated to reflect the impact of the share split.

RATIOS	**2005**	2004	2003
Return on average common shareholders' equity (%)[1]	**27.3**	21.3	15.4
Return on average capital employed (%)[2]	**26.8**	19.9	13.1
Common share dividends as percentage of earnings[3]	**15.0**	20.1	27.9
Price to earnings ratio[4]	**17.2**	17.1	20.8
Current assets to current liabilities	**1.3**	0.9	0.5
Reinvestment ratio (%)[5]	**56.1**	44.7	41.9
Total debt as percentage of capital employed[6]	**2.5**	2.1	13.8
Debt to cash flow (%)[7]	**6.9**	6.4	52.0

[1] Earnings divided by average common shareholders' equity.

[2] Earnings plus after-tax interest expense divided by average of opening and closing capital employed. Capital employed is a total of equity, long-term debt and short-term borrowings.

[3] Common share dividends paid divided by earnings.

[4] Closing share price at December 31 divided by earnings per share.

[5] Capital, exploration, predevelopment and investment expenditures divided by cash flow from operations (During 2005, capital, exploration and predevelopment was reclassified on the *Consolidated Statement of Cash Flows*. See Note 1 to the consolidated financial statements).

[6] Total debt divided by total debt plus equity.

[7] Total debt divided by cash flow from operations. (During 2005, capital, exploration and predevelopment was reclassified on the *Consolidated Statement of Cash Flows*. See Note 1 to the consolidated financial statements).

EMPLOYEES	**2005**	2004	2003
Employees (number at year-end)	**4 564**	4 003	3 850

STOCK-TRADING INFORMATION	**2005**					2004				
	Quarter				Total	Quarter				Total
	1st	2nd	3rd	4th	Year	1st	2nd	3rd	4th	Year
Share prices (dollars)[1]										
High	**31.67**	**34.39**	**41.62**	**42.35**	**42.35**	21.95	22.13	23.15	26.68	26.68
Low	**25.11**	**26.84**	**33.30**	**32.45**	**25.11**	19.23	20.44	20.68	22.83	19.23
Close (end of period)	**29.00**	**32.89**	**40.65**	**42.05**	**42.05**	20.68	21.50	23.00	26.66	26.66
Shares traded (thousands)[1]	**32 017**	**21 961**	**22 362**	**23 719**	**100 059**	22 177	19 550	17 130	21 213	80 070

[1] Toronto Stock Exchange quotations.

OFFICERS *(all in Calgary)*

Clive Mather
President and Chief Executive Officer

Cathy L. Williams
Chief Financial Officer

VICE PRESIDENTS

Brian E. Straub
Senior Vice President, Oil Sands

H. Ian Kilgour
Senior Vice President, Exploration & Production

David M. Weston
Senior Vice President, Oil Products

Graham Bojé
Vice President, Manufacturing and Supply

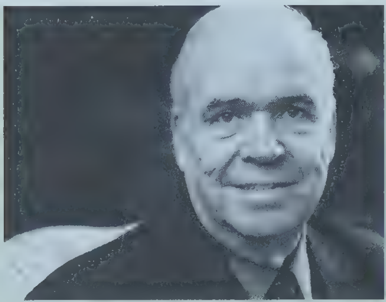
Rob W.P. Symonds
Vice President, Foothills

Timothy J. Bancroft
Vice President, Sustainable Development, Technology and Public Affairs

R. David Fulton
Vice President, Human Resources

TREASURER
Matthew B. Haney

CONTROLLER
Donna Tarka



Derek H. Burney, O.C. (2) (3) (4) (5)
Ottawa, Ontario

Lead Director, Chair of the Nominating and Governance Committee

On the board of directors since April 25, 2001.

Since 2004, Mr. Burney has been Chairman of New Brunswick Power Corporation, a Crown corporation. From 1999 to 2004, Mr. Burney served as President and Chief Executive Officer of CAE Inc., a provider of technologies used in the aerospace and defence sectors.

Mr. Burney also serves as a director of TransCanada Corporation, TransCanada Pipelines Limited, CanWest MediaWorks Inc. and CanWest Global Communications Corp. He is Chairman of the Confederation College Foundation, an advisory board member of Idelix Software Inc. and a Fellow at the Canadian Defense and Foreign Affairs Institute. He is a Senior Distinguished Fellow and Visiting Professor of Carleton University.

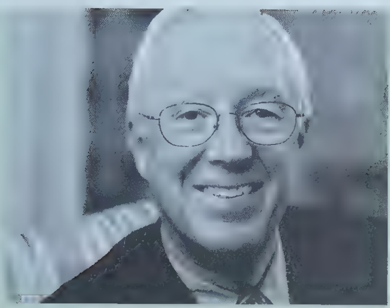
Ida J. Goodreau (1) (3) (5)
Vancouver, British Columbia

On the board of directors since April 24, 2003.

Since 2002, Ms. Goodreau has been President and Chief Executive Officer of the Vancouver Coastal Health Authority, which shares responsibility with five other geographical health authorities and ministries of the British Columbia provincial government for planning, delivering, monitoring and evaluating health-care programs in the province.

From 2000 to 2002, Ms. Goodreau was Senior Vice President, Global Optimization and Human Resources, Norske Skog Industries.

Member of the:
(1) *Audit Committee*
(2) *Nominating and Governance Committee*
(3) *Management Resources and Compensation Committee and Pension Subcommittee*
(4) *Reserves Committee*
(5) *Health, Safety, Environment & Social Responsibility Committee*



Kerry L. Hawkins (1) (2) (4) (5)
Winnipeg, Manitoba

Chair of the Audit Committee

On the board of directors since October 1, 1997.

Mr. Hawkins was President of Cargill Limited, a Canadian agricultural company, from 1982 until his retirement at the end of November 2005.

Mr. Hawkins also serves as a director of TransCanada PipeLines Limited, TransCanada Corporation, Hudson's Bay Company and Nova Chemicals Corporation.

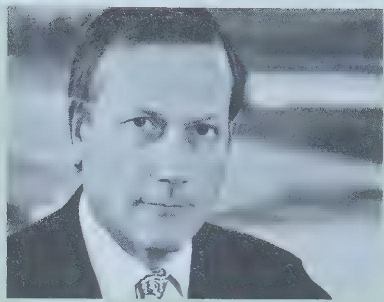
David W. Kerr (1) (2) (4) (5)
Toronto, Ontario

Chair of the Reserves Committee

On the board of directors since April 24, 2003.

Since June 2002, Mr. Kerr has been Chairman and a director of Falconbridge Limited (previously Noranda Inc.), a leading international mining and metals company. From 2001 to 2002, Mr. Kerr was Chairman and Chief Executive Officer of Falconbridge Limited and from 1990 to 2001, he served as President and Chief Executive Officer of Falconbridge Limited.

Mr. Kerr also serves as a director of Sun Life Financial Inc. and Brookfield Asset Management Inc.



W. Adrian Loader
Guildford, England

On the board of directors since September 27, 2003.

Since July 2005, Mr. Loader has served as Director, Strategy and Business Development for Royal Dutch Shell plc and was previously Director, Strategic Planning, Sustainable Development and External Affairs for Shell International Limited since June 2003. He was President, Shell Oil Products Europe from 1999 until June 2003. The main businesses of all Shell Group companies are oil, natural gas, chemicals and renewable resources.

Mr. Loader also serves as a director of other Shell Group companies and Alliance Unichem Plc.

Clive Mather
Calgary, Alberta

On the board of directors since August 1, 2004.

Since August 1, 2004, Mr. Mather has been President and Chief Executive Officer of Shell Canada Limited.

Mr. Mather served as Chairman of Shell U.K. Limited and Head of Global Learning of Shell International Limited from 2002 to 2004. Before that, he was Special Advisor to the Chairman of the Committee of Managing Directors of Shell International Limited. After serving as Director, International, of Shell International Limited, Mr. Mather was Chief Executive Officer of Shell Services International Ltd. from 1999 to 2001.

Mr. Mather is a director and President of Shell Investments Limited and a director of Shell Chemicals Canada Ltd., Shell Canada Products Limited and Shell Canada OP Inc.

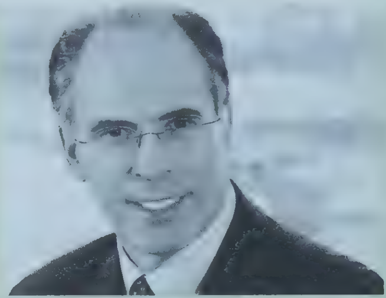
Ronald W. Osborne (1) (3) (4)
Toronto, Ontario

Chair of the Management Resources and Compensation Committee and Pension Subcommittee

On the board of directors since April 25, 2001.

Since May 2005, Mr. Osborne has been Chairman of Sun Life Financial Inc. and its wholly owned subsidiary Sun Life Assurance Company of Canada. From 1999 to 2003, Mr. Osborne was President and Chief Executive Officer of Ontario Power Generation Inc., which owns the power generation assets supplying approximately 85 per cent of all electricity consumed in Ontario.

Mr. Osborne also serves as a director of Torstar Corporation, St. Lawrence Cement Group Inc., Massachusetts Financial Services Company, Four Seasons Hotels Inc., Nortel Networks Corporation, Nortel Networks Limited and as trustee of RioCan Real Estate Investment Trust.



Rob Routs
The Hague, the Netherlands

Chair of the Meetings of the Board

On the board of directors since April 29, 2005.

Mr. Routs is an executive director of Royal Dutch Shell plc and was previously a managing director of the Royal/Dutch Group since 2003. From 2002 to 2003, Mr. Routs served as President and Chief Executive Officer of Shell Oil Products U.S., President of Shell Oil Company and Country Chair for the Shell Group in the United States. He was President and Chief Executive Officer of Equilon Enterprises LLC from 2000 to 2002 and, before that, Mr. Routs was Head of Shell International Resource and Technical Services Group (Shell Global Solutions).

Member of the:

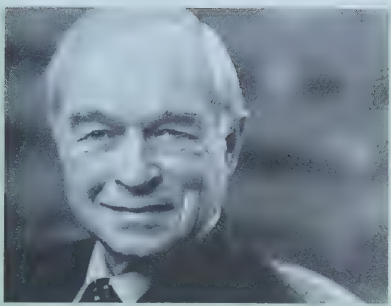
(1) *Audit Committee*

(2) *Nominating and Governance Committee*

(3) *Management Resources and Compensation Committee and Pension Subcommittee*

(4) *Reserves Committee*

(5) *Health, Safety, Environment & Social Responsibility Committee*



Raymond Royer, O.C. (1) (3)
Île-Bizard, Quebec

On the board of directors since April 26, 2000.

Since 1996, Mr. Royer has been President and Chief Executive Officer of Domtar Inc., a North American manufacturer of fine papers, pulp and forest products with a 50 per cent interest in Norampac Inc., which manufactures containerboard and corrugated containers.

Mr. Royer also serves as a director of Domtar Inc. and Power Financial Corporation.

Nancy C. Southern (2) (3) (5)
Calgary, Alberta

Chair of the Health, Safety, Environment & Social Responsibility Committee

On the board of directors since April 25, 2001.

Ms. Southern has been President and Chief Executive Officer of ATCO Ltd. and Canadian Utilities Limited since January, 2003. From 2000 to December 2002, Ms. Southern was Co-Chairman and Chief Executive Officer of ATCO Ltd. and Canadian Utilities Limited.

Ms. Southern also serves as Director and Chief Executive Officer of certain other subsidiaries of ATCO Ltd. and Canadian Utilities Limited. She is a director of the Bank of Montreal and Akita Drilling Ltd. and is Executive Vice President of Spruce Meadows.

Shell Canada believes that sound corporate governance practices contribute to the effective management of the Company and the achievement of its goals.

The Company's corporate governance practices are aligned with the standards of the Canadian Securities Administrators set forth in National Instrument 58-101 *Disclosure of Corporate Governance Practices* and National Policy 58-201 *Corporate Governance Guidelines*. A complete description of the Company's approach to corporate governance is contained in its *Statement of Corporate Governance Practices* attached as Appendix 2 to the *Management Proxy Circular* dated March 10, 2006.

Key Practices

Key aspects of Shell Canada's approach to corporate governance are:

> appointment of a Lead Director (the board of directors appointed its first Lead Director in 2005);

> an independence policy for directors;

> 100 per cent independence of all five committees of the board (no officer or employee representing the Company or its majority shareholder may sit on these committees);

> sessions of the board and committees held without management present and separate meetings of the independent directors held in connection with all board meetings;

> written charters for the board and committees;

> written position descriptions for the Chairman of the Meetings of the Board, the Lead Director, the directors and the chairs of the committees;

> requirement for all independent directors and Shell Canada's President and Chief Executive Officer to hold shares in the Company equal to three years' board annual retainer fees (currently $50,000 per year) after five years of board service;

> regular evaluations by the board of its effectiveness;

On a visit to the Montreal East Refinery (MER) in August 2005 are pictured, left to right: Bob Baird, MER Refinery Manager; Kerry Hawkins, director and Chair of the Audit Committee; Rob Routs, director and Chair of the Meetings of the Board; Nancy Southern, director and Chair of the Health, Safety, Environment & Social Responsibility Committee; Clive Mather, director and President & CEO; Debbie Baluch, ultra-low-sulphur diesel (USLD) Project Engineer; Robert Guertin, USLD Project Coordinator; and Réal Gagnon, USLD Project Manager.

> orientation and continuous education in the businesses of Shell Canada available to all members of the board;

> board approval of Shell Canada's strategic plans;

> annual review of the adequacy and form of compensation of directors (including minimum share ownership requirements) by the Nominating and Governance Committee;

> three financial experts on the Audit Committee;

> annual review of succession planning and talent by the Management Resources and Compensation Committee;

> annual review of the performance of Shell Canada's Chief Executive Officer and annual approval of his and other senior executives' compensation by the Management Resources and Compensation Committee;

> application of a *Code of Ethics and Statement of General Business Principles* to all directors, officers and employees;

> a Corporate Disclosure Policy which describes and governs the Company's corporate disclosure practices;

> procedures for reporting accounting or auditing concerns or complaints to the Audit Committee; and

> systems that allow shareholders, employees and other members of the public to communicate with the board of directors, management, the Chief Compliance Officer or the Ombuds office.

Board of Directors

The board of directors is responsible for overseeing the business and affairs of Shell Canada in a stewardship role. The day-to-day management is delegated to the officers of the Company. Any responsibilities that have not been delegated to the officers or to a committee of the board remain with the board.

The board is composed of 10 directors. Seven of the directors are independent and have no material relationship with either the Company or its majority shareholder. The board reviews its composition and size once a year and believes this fairly reflects the investment of minority shareholders. Ten directors will be nominated for election at the Annual and Special Meeting of shareholders in 2006.

The board holds six regularly scheduled meetings each year, plus special board meetings as required from time to time. Shell Canada's bylaws state that the quorum for any meeting of the board shall be two directors.

Committees

The board of directors has established the following committees:

- Audit Committee
- Reserves Committee
- Management Resources and Compensation Committee and Pension Subcommittee
- Nominating and Governance Committee
- Health, Safety, Environment & Social Responsibility Committee

Only independent directors sit on these committees. Each committee member knows the mandate of the committee on which they serve and conducts activities that are consistent with and fulfill the committee's mandate.

The charters of the board and its committees can be found on the Company's website at **www.shell.ca**.

Selection of Directors

The shareholders of Shell Canada elect the board of directors each year at the annual meeting of shareholders. The Nominating and Governance Committee recommends new appointments and reappointments to the board for consideration by the shareholders.

A director must retire at the next annual meeting of shareholders following his or her 70th birthday.

Chairman of the Meetings of the Board and Lead Director

Mr. Robert J. Routs serves as Chairman of the Meetings of the Board. Mr. Routs is a member of the executive committee of Royal Dutch Shell plc (the Company's majority shareholder) and therefore is not an independent director. To complement this role, the board appointed Mr. Derek H. Burney, an independent director, as Lead Director in March 2005.

The Chairman of the Meetings of the Board is expected to:

> consult with the President and CEO and the Secretary of the Company to determine the dates and locations of meetings of the board and the shareholders;

> require the board to meet at least six times annually and as many more times as necessary for the board to carry out its duties and responsibilities effectively;

> ensure that all the required business is brought before a meeting of shareholders;

> in consultation with the President and CEO and the Secretary of the Company, review the meeting agendas to ensure all required business is brought before the board to enable the board to carry out its duties and responsibilities;

> attend all meetings of the board and the shareholders except as otherwise authorized by the bylaws;

> ensure the board has the opportunity to meet separately without management present at all meetings;

> provide leadership to enable the board to act as an effective team in carrying out its duties and responsibilities; and

> advise, counsel and mentor the President and CEO and fellow members of the board.

The Lead Director is expected to:

> ensure that the board functions independently of management of the Company;

> ensure that independent directors have adequate opportunities to meet without management present;

> chair separate meetings of the independent directors;

> represent the independent directors in communications with shareholders, as appropriate;

> be available to directors who have concerns that cannot be addressed by the Chairman of the Meetings of the Board; and

> perform such other functions as may be reasonably requested by the board or the Chairman of the Meetings of the Board.

Board Evaluations

The Chairman of the Nominating and Governance Committee conducts an annual assessment of the board, individual directors, the Chairman of the Meetings of the Board and the chairs of the committees. He then prepares a summary report for the board. The assessment includes:

> measuring performance against key responsibilities, including strategy, succession planning, performance management, compliance, financial oversight and risk management; and

> assessing board resources and capabilities, including knowledge, contribution of fellow directors, information, authority and time.

Shell Canada believes this annual assessment is a constructive means to assess the effectiveness of the board and to formulate recommendations for improvement.

Director Education

New board members receive a minimum two-day orientation that includes a tour of some of Shell Canada's major operating facilities. All new directors receive a manual containing the charters of the board and its committees and other relevant corporate, policy and business information. The chairs of the committees provide regular reports to the board on activities completed by each committee. Senior management makes regular presentations to the board on the main areas of the Company's business.

Shell Canada offers a continuing education program for its directors, which focuses on Shell Canada's business and corporate governance practices. Some aspects of Shell Canada's continuing education program for directors include:

> special sessions conducted regularly by members of senior management on their individual areas of expertise;

> membership for each director in an organization dedicated to improving the profession of directorship in Canada; and

> tours of Shell Canada's major operating facilities and discussions with the President and CEO regarding areas of specific interest.

Project Coordinator Robert Guertin accompanied Shell director Nancy Southern on the construction site of the ultra-low-sulphur diesel unit at the Montreal East Refinery.

Meeting Procedures

The President and CEO establishes the agenda for each board meeting in collaboration with the Chairman of the Meetings of the Board. All meeting materials for both the board and the committees are distributed approximately one week in advance of the respective meetings to provide the board with sufficient time to review and prepare for the directors and committee meetings.

Access to Management and Outside Advisors

All directors have access to management of the Company. Directors may hire outside advisors at the Company's expense, subject to the approval of the Nominating and Governance Committee. Each committee is authorized to retain outside advisors.

Communication with Shareholders

Any shareholder is invited to contact the board by e-mail at **corporatesecretary@shell.com** or in writing to:

Board of Directors
Shell Canada Limited
Shell Centre
6th Floor, 400 – 4th Avenue S.W.
Calgary, Alberta, Canada T2P 0J4
Attention: Secretary

The Secretary will review each communication and determine the appropriate action to be taken with the board or any of its committees.

INVESTOR INFORMATION

SHELL CANADA LIMITED

(incorporated under the laws of Canada)

HEAD OFFICE

Shell Centre
400 – 4th Avenue S.W.
Calgary, Alberta, Canada T2P 0J4
Telephone (403) 691-2175
Website www.shell.ca

TRANSFER AGENT AND REGISTRAR

CIBC Mellon Trust Company
P.O. Box 7010 Adelaide Street Postal Station
Toronto, Ontario, Canada M5C 2W9
E-mail inquiries@cibcmellon.com
Website www.cibcmellon.com
Facsimile (416) 643-5501
Answerline (416) 643-5500 or
1-800-387-0825
Toll-free throughout North America

STOCK EXCHANGE LISTINGS

The common shares of Shell Canada Limited are listed on the Toronto Stock Exchange (stock symbol SHC) and do not have an established public trading market in the United States.

ANNUAL AND SPECIAL MEETING

The Annual and Special Meeting of shareholders will be held at 11:00 a.m., Friday, April 28, 2006, in the Wildrose Ballroom, Sheraton Suites Eau Claire, Calgary, Alberta.

DUPLICATE REPORTS

Shareholders who receive more than one copy of Shell Canada's *Interim Reports* and the *Annual Report* as a result of having their shareholdings represented by two or more share certificates may wish to contact the transfer agent to have their holdings consolidated. It will not be necessary to forward share certificates.

ANNUAL INFORMATION FORM AND 2005 SUSTAINABLE DEVELOPMENT REPORT

The Corporation's *Annual Information Form* for 2005 and the *2005 Sustainable Development Report* are available to shareholders on request from the Corporation's Secretary at Shell Canada's head office.

OWNERSHIP AND VOTING RIGHTS OF SHELL CANADA LIMITED

(as at December 31, 2005)

Shell Canada is a Canadian corporation. Ownership of the Company is divided between public shareholders (approximately 22 per cent) and Shell Investments Limited (approximately 78 per cent). Shell Investments Limited is owned by Shell Petroleum N.V., which, in turn, is owned by Royal Dutch Shell plc, an English company with headquarters in the Netherlands.

APPROXIMATE CONVERSION FACTORS

1 cubic metre of liquids	= 6.29 barrels
1 cubic metre of gases	= 35.3 cubic feet
1 barrel of oil equivalent	= 6,000 cubic feet of gases
1 tonne	= 2,205 pounds
	= 0.984 long ton
	= 1.102 short tons
1 kilometre	= 0.621 mile
1 hectare	= 2.47 acres
1 litre	= 0.22 gallon

Mixed Sources
Product group from well-managed forests, controlled sources and recycled wood or fiber
www.fsc.org Cert no. SW-COC-1715
FSC

This report was printed in Canada by Sundog Printing using FSC Certified paper for the text pages. The FSC paper, paper mills and printer are all Forest Stewardship Council certified, which is an international network that promotes environmentally appropriate and socially beneficial management of the world's forests. The report was produced in a printing facility that results in nearly zero volatile organic compound (VOC) emissions. Sundog Printing's certification number is SW-COC-1715.

This annual report has been printed using vegetable-based inks. The cover paper is recyclable. The text paper is FSC certified. The financial pages contain 30% pcw fibre and is FSC certified. The transparent pages are not recyclable.

Shell Canada Limited

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